CALIFORNIA ENERGY COMMISSION

COMMITTEE DRAFT TRANSMITTAL OF *2005 ENERGY REPORT* RANGE OF NEED AND POLICY RECOMMENDATIONS TO THE CALIFORNIA PUBLIC UTILITIES COMMISSION

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Arnold Schwarzenegger, *Governor*

CALIFORNIA ENERGY COMMISSION

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This report was prepared by the California Energy Commission's Integrated Energy Policy Report Committee as part of *2005 Integrated Energy Policy Report* proceeding - docket # (04-IEP-1K). The report will be considered for adoption by the full Energy Commission at its Business Meeting on November 4, 2005. The views and recommendations contained in this document are not official policy of the Energy Commission until the report is adopted.

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1. Introduction

Since the adoption of the *Integrated Energy Policy Report* (*Energy Report*)[1] in 2003, the California Energy Commission (Energy Commission) and California Public Utilities Commission (CPUC) have worked to ensure close coordination of the *2005 Energy Report* proceeding with the upcoming CPUC 2006 long-term procurement proceeding. This *Transmittal of the 2005 Energy Report Range of Need and Policy Recommendations to the CPUC* (*Transmittal Report*) is the result of that cooperation. This report summarizes the key policy recommendations from the *Committee Draft 2005 Integrated Energy Policy Report* (*Draft Energy Report*)[2] and the record on which those recommendations are based. This *Transmittal Report* also provides the CPUC with the data and analyses used by the Energy Commission to asses the demand forecasts and resource needs for the state's three largest investor-owned utilities (IOUs): San Diego Gas and Electric Company (SDG&E), Southern California Edison Company (SCE), and Pacific Gas and Electric Company (PG&E). The CPUC has stated its intention to use this information on the IOU demand forecasts and resource needs developed in the *2005 Energy Report* proceeding as the basis for its 2006 long-term procurement proceeding.

2. Background

2.1. 2005 Energy Report Proceeding

The Energy Commission is directed by statute to prepare an *Energy Report* every two years. This report must contain an overview of major energy trends and issues facing the state. In order to ensure consistency in the information underlying state energy policy and decisions, other state agencies and entities are directed to carry out

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[1] *2003 Integrated Energy Policy Report (2003 Energy Report)*, California Energy Commission, publication 100-03-019, December, 2003.

[2] *Committee Draft 2005 Integrated Energy Policy Report (Draft Energy Report)*, California Energy Commission, CEC-100-2005-007-CTD, September, 2005.

their energy-related responsibilities using the information and analyses in the *Energy Report*. (Pub. Resources Code, § 25302.)

The 2005 Energy Report proceeding began when the Energy Report Committee (Commissioner John L. Geesman, Presiding Member, and Commissioner James D. Boyd, Associate Member) issued a Notice of Committee Hearing for an August 18, 2004 hearing on the scope of the 2005 Energy Report proceeding. At the hearing, the Committee received comments and discussed the appropriate scope of issues for the 2005 Energy Report. On September 3, 2004, the Committee issued a scoping order identifying a list of issues to be addressed in the *2005 Energy Report*.[3] The issues were grouped into the following major categories:

- California's Energy Demand, Supply, and Infrastructure.
  - Transportation Fuel Demand, Supply, and Infrastructure.
  - Electricity Demand, Supply, and Infrastructure.
  - Natural Gas Demand, Supply, and Infrastructure.
- Energy, Environmental, and Economic Sustainability.
- California-Baja California Border Issues.

In order to establish a comprehensive information base for decision making, the Committee directed certain market participants to provide a broad range of information related to electricity supply and retail price, electricity demand, natural gas supply and price, transmission issues, and environmental issues. In addition, Energy Commission staff, numerous other state agencies, market participants, and members of the public submitted papers, analyses, and comments. Prior to publication of the *Draft Energy Report* and *Committee Draft Strategic Transmission Investment Plan (Draft Strategic Plan)*,[4] the Committee held 53 public hearings and workshops and received more than 50 staff and consultant papers and reports, with extensive participation by more than 600 public and private entities and individuals. The evidentiary record compiled over the course of the 2005 Energy Report proceeding exceeds 25,000 pages. Key reports relating to issues addressed in this transmittal report included:

- *Assessment of California CHP Market and Policy Options for Increased Penetration.*

[3] Committee Scoping Order, Docket 04-IEP-1, September 3, 2004.

[4] *Committee Draft Strategic Transmission Investment Plan (Draft Strategic Plan)*, California Energy Commission, CEC-100-2005-006-CTD, September, 2005.

- *Investor-Owned Utility Resource Plan Summary Assessment.*
- *Resource Plan Aggregated Data Results.*
- *Preliminary Reference Case in Support of the 2005 Natural Gas Market Assessment.*
- *California Energy Demand 2006-2016 - Staff Energy Demand Forecast, Staff Draft Report.*
- *Energy Demand Forecast Methods Report.*
- *Electricity Demand Forecast Comparison Report.*
- *California and Western Electricity Supply Outlook Report.*
- *Implementing California's Loading Order for Electricity Resources.*
- *California Energy Demand 2006-2016 - Staff Energy Demand Forecast Revised September 2005.*
- *Upgrading California's Electric Transmission System: Issues and Actions for 2005 and Beyond.*
- *Revised Reference Case in Support of the 2005 Natural Gas Market Assessment.*

After consideration of all of the papers, reports, written comments and discussions at hearings and workshops, the Committee has published the *Draft Energy Report* and the *Draft Strategic Plan*. The *Draft Energy Report* addresses specific energy issues associated with transportation fuels; electricity needs and procurement policies; electricity resources; transmission; natural gas; water/energy interaction; global climate change; and energy concerns in the California-Mexico border region. It also identifies policy options and recommended strategies for achieving the state's energy goals. As discussed below, this *Transmittal Report* contains those assessments and recommendations that are specific to the load-serving entities (LSEs) that fall under the CPUC's jurisdiction, including the three largest IOUs: SDG&E, SCE, and PG&E.

The Committee held a public hearing on the *Draft Strategic Transmission Plan* and six public hearings on the *Draft Energy Report*, and has received extensive comment which it is considering in preparing the final versions of the *Strategic Transmission Plan* and the *Energy Report* in early November 2005. The *Committee Final Transmittal Report*, which will be published in mid-November, will reflect any changes to the other two documents and include responses to comments received on this *Draft Transmittal Report*. All three reports will be considered for adoption by the full Energy Commission at a special business meeting on November 21, 2005.

2.2. Coordination with the CPUC

Early in the 2005 Energy Report proceeding, the Energy Commission and the CPUC began discussions about integrating the 2005 Energy Report with the CPUC's upcoming 2006 long-term procurement proceeding. Michael R. Peevey, the President of the CPUC and the Assigned Commissioner for the CPUC Order Instituting Rulemaking (OIR) to Promote Policy and Program Coordination and Integration in Electric Utility Resource Planning (R. 04-04-003), issued an Assigned Commissioner's Ruling (ACR) in September 2004, stating that the 2005 Energy Report process should serve as the "initiation of a new, integrated, statewide resource planning process."[5] In the ACR, President Peevey specifically identified the 2005 Energy Report process as the appropriate forum to consider load forecasting, resources assessment and scenario issues, and to establish the appropriate range of resource portfolio expansion for LSEs in California. In fact, President Peevey was explicit that the CPUC would not, in its 2006 procurement proceeding, reevaluate the range of need established by the Energy Commission in the 2005 Energy Report proceeding, unless so required by law. Stakeholders interested in participating in the development of such analyses were directed to "do so in the context of the [Energy Commission's Integrated Energy Policy Report] process."[6]

On March 14, 2005, President Peevey issued a more detailed ACR as part of R.04-04-003.[7] This ACR explicitly placed parties on notice that they would not be allowed to relitigate the Energy Commission's determination of the appropriate level and range of resource needs for LSEs, absent new information, or materially changed circumstances.[8] The March ACR identified the process the Energy Commission would follow in developing this determination and addressed the contents of this *Transmittal Report*. Specifically, the ACR stated that, after conducting public proceedings, including any hearings necessary pursuant to Public Utilities Code Section 1822, the Energy Commission would develop a report identifying the likely range of statewide and IOU-specific need, discussing issues relevant to these determinations, and responding to participant comments.[9] According to the ACR, the Transmittal Report would be based

[5] President Peevey ACR, R.04-04-003, September 16, 2004.

[6] *Id.* at p. 3.

[7] President Peevey ACR, R.04-04-003, March 14, 2005.

[8] *Id*. at p. 6.

[9] *Id*. at p. 7.

on the information and comments provided in the proceeding.[10] The ACR was served on all parties to R. 04-04-003 and to the umbrella proceedings.[11] The Committee issued an Order on the same day stating that the Order and the ACR had been fully coordinated between the two agencies.[12] The upcoming comment period and hearing on this *Draft Transmittal Report* provide the last opportunities for parties to express their concerns or positions regarding the LSE need determinations to be used in the 2006 CPUC procurement proceeding.

The March 14, 2005, ACR also addressed the issue of intervenor compensation. The CPUC is required to implement a comprehensive compensation system for intervenors whose participation results in a "substantial contribution" to CPUC proceedings. The CPUC recognized that this requirement raises a question of whether participants in the 2005 Energy Report proceeding, who make a substantial contribution to those portions of the 2005 Energy Report proceeding that will be used in CPUC's 2006 procurement proceeding, are eligible for compensation. The CPUC decided that such compensation is appropriate. Accordingly, the ACR established a process by which participants in both proceedings could apply for and, if eligible, receive compensation. This process requires the Energy Commission to provide the CPUC with a written assessment of a claim of substantial contribution within 75 days of an intervenor request for compensation for participation in the 2005 Energy Report proceeding. The Utility Reform Network (TURN), the Natural Resources Defense Council (NRDC), the Union of Concerned Scientists (UCS), the Green Power Institute, and Women's Energy Matters (WEM) filed notices of intent to claim compensation for work conducted in the 2005 Energy Report proceeding and participated in various parts of the proceeding.

[10] *Ibid.*

[11] These include: R. 01-0 8-028, R. 04-04-025, R. 03-10-003, I. 00-11-001, R. 04-01-026, R. 04-04-026, R. 04-03-017, R. 02-06-001, and R. 04-01-025.

[12] Order Re: Coordination With CPUC's 2006 Procurement Proceeding, Docket 04-IEP-1, March 14, 2005.

2.3. Confidentiality

Confidentiality issues were a major source of discussion and debate in the 2005 Energy Report proceeding, culminating in two IOU lawsuits against the Energy Commission to prevent the release of IOU-provided bundled customer annual peak demand forecasts and tables including aggregations of IOU-supplied resource plan data.[13] These suits underscore the level of contention regarding the Energy Commission's decision to conduct the Energy Report proceeding in an open and accessible forum, and highlight differences in the way planning activities are undertaken by the Energy Commission and the CPUC.

In recent years the electric resource planning process at the CPUC has been shrouded by a significant degree of secrecy. Under the current CPUC process, CPUC staff and some non-market participants who have signed non-disclosure agreements are allowed to review the utility procurement plans and implementation activities through the use of non-disclosure agreements and protective orders. As a result, scrutiny of assumptions and debate over alternatives is severely truncated. This secretive process can only undermine public confidence in the regulatory decisions made in this environment. The Energy Commission firmly believes that significant benefits accrue from rigorous public scrutiny of data and planning assumptions, and that responsible and effective electricity resource planning should not and can not exclude the public.

Conversely, conducting policymaking by using information that is not publicly available hinders the Energy Commission's accountability to the public, to the Legislature, and to the Governor. When we cannot discuss the information that underlies our decisions, we lose the ability to be responsive to those who have a right to understand our decisions. As a result, for decision-making purposes, the Energy Commission has not relied on information that is not available for public review and discussion at public workshops.

[13] SCE filed the suit to prevent release of its bundled-customer annual peak demand forecast. Energy Commission staff have agreed not to release the peak forecasts from PG&E and SDG&E based on an agreement among attorneys for the Energy Commission and the IOUs that the disputed data would remain confidential until any court action was resolved. The three IOUs filed a joint action relating to the aggregated data tables.

We note that our approach is compelled by the Public Records Act (PRA), which is designed to safeguard the accountability of government to the public. Because it serves this important public interest by securing public access to government records, the PRA is construed broadly in favor of access and exemptions from disclosure are construed narrowly. We are using the 2005 Energy Report record to set important state energy policy, including how much and what kind of electrical generation and transmission are necessary for the state's future. There is a strong public interest in having the information underlying such policy decision-making accessible to the public and interested parties, rather than using a process that is not subject to public discussion or critique.

Our approach is also required by the Warren-Alquist Act (Pub. Resources Code § 25000 et seq.) which directs the Energy Commission to "gain the perspectives of the public and market participants" in developing the *Energy Report*. (Pub. Resources Code, § 25306.) This approach is also consistent with the State Constitution, which expressly states that the public has the right to access information concerning the conduct of the people's business, and that statutes and regulations shall be broadly construed if they further the people's right of access and narrowly construed if they limit the right of access. (Cal. Const., art. I, § 3, subd. (b)(1) and (2).)

Finally, we note that disagreements between LSEs and the Energy Commission regarding claims for confidentiality have consumed a significant amount of scarce staff resources in this 2005 Energy Report cycle.

As stated in the *Draft Energy Report*:

> The Energy Commission believes that public disclosure of demand forecasts and resource plans, in both energy and capacity terms, is critical to a sound, transparent planning process responsive to the public it serves. Greater disclosure is warranted for California IOUs in light of their size and the regulatory protection they enjoy as regulated monopolies. A more open environment is also consistent with the Public Records Act, which is designed to ensure the accountability of government to the public. It is broadly worded in favor of open access, and exceptions are narrowly defined.
>
> The Energy Commission is committed to the rigorous public scrutiny of data and planning assumptions and believes that responsible and effective resource planning should not and cannot exclude the public. The 2005 Integrated Energy Policy Report Committee has therefore elected to rely exclusively upon publicly disclosed information as its basis for its assessments, findings, and policy recommendations in this proceeding. The Energy Commission believes that resource planning and procurement in California should be open and

> transparent and will work cooperatively with the CPUC through its rulemaking process to revise regulations governing disclosure of records.[14]

Given the strong public policy favoring accessibility to information and transparency of the decision-making process, the Energy Commission will actively pursue steps to minimize conflicts about confidentiality in future Energy Report proceedings. We plan to participate in the CPUC's OIR to Implement Senate Bill No. 1488 (2004 Cal. Stats., Ch. 690 (Sept. 22, 2004)) Relating to Confidentiality of Information (R.05-06-040). We will also conduct a rulemaking to revise Energy Commission regulations regarding data collection and information disclosure for future Energy Report proceedings. We will vigorously defend our own determinations that certain information should be publicly available, and, if appropriate, seek long-term legislative solutions to ensure that state government has a consistent policy that allows the Energy Report process to be conducted without withholding information from participants, the Legislature, and the public.

3. General Procurement Policy Recommendations

The Energy Commission has included in the *2005 Energy Report* policy recommendations based on the analyses conducted during this proceeding. These recommendations cover a broad range of topics. In this portion of the *Transmittal Report*, we specifically identify those *Energy Report* policy recommendations that should be implemented by the CPUC in the upcoming 2006 long-term procurement proceeding.

The starting point for these recommendations is the loading order. The loading order was first identified in the *Energy Action Plan (EAP) I*[15] and the *2003 Energy Report*. It was subsequently endorsed by Governor Schwarzenegger, and was recently re-affirmed with the adoption of *EAP II*.[16] The loading order (efficiency, demand response,

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[14] *Draft Energy Report*, p. 47.

[15] *Energy Action Plan (EAP I)*, California Power Authority, California Public Utilities Commission, and California Energy Commission, April 2003. The *Energy Action Plan* is an implementation roadmap adopted by the state's key energy agencies for ensuring consistency in implementing the state's energy policies and objectives.

[16] *Energy Action Plan II: Implementation Road Map for Energy Policies (EAP II)*, California Public Utilities Commission and California Energy Commission, September 2005.

renewable power, distributed generation, clean and efficient fossil-fired generation) is the state's priority sequencing policy for preferred options that address increasing energy needs while considering the need to improve the transmission grid and distribution infrastructure.

In addition, we offer several recommendations based on our mandate to facilitate efficient and reliable energy markets. (Pub. Resources Code, § 25301 (b)(5).) Specifically, we find that several improvements to the CPUC's procurement process would help achieve this goal. Together, these policy recommendations should help ensure that the state's policy objectives are clearly and consistently promoted throughout the 2006 procurement proceeding.

3.1. Implementation of the Loading Order

3.1.1. Need for Long-Term Contracts

One important step in implementing the loading order will be an increased emphasis on the use of long-term contracts to meet utilities' needs. A careful review of the record developed during this proceeding demonstrates that policies encouraging long-term contracts would increase deployment of both new renewable and new conventional generation, provide a hedge against increasing natural gas prices, and increase environmental and reliability benefits associated with diminished reliance on the state's aging fleet of existing plants. In the *Draft Energy Report*, the Committee finds that the lack of available long-term contracts has hindered development of more than 7,000 megawatts (MW) of generation from facilities that are already permitted.[17]

No regulatory barriers to long-term contracts currently exist. As noted by the CPUC in the July 7, 2005, hearing on electricity issues and policy options, IOUs are capable of entering into longer-term contracts.[18] Nonetheless, a majority of the capacity sought under current procurement is under medium- or short-term contracts.

Use of short-term contracts perpetuates reliance on aging and inefficient infrastructure and impedes construction of the backlogged new resources that have already received licenses. As noted in the *2004 Energy Report Update*, aging power plants

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[17] *Draft Energy Report*, p. E-2.

[18] 7/7/05 RT, p. 40.

currently play an important role in the state's electricity system, including "provid[ing] local reliability services…; contribut[ing] to regional and statewide reliability…; and help[ing] alleviate transmission system congestion…."[19] While these plants have provided needed resources during the last several years and will unavoidably play a role in the near term, the state cannot afford to rely indefinitely on power plants that are 30 years old and older. Instead, we must begin an orderly process to retire them.[20]

The lack of long-term contracts also hinders the development of renewable resources. Ms. Julee Malinowski-Ball, representing Public Policy Advocates, stated at the May 9, 2005 hearing on renewable resource potential that long-term, fixed-price contracts are needed to promote the development of additional renewable resources. [21]

We also note that the extensive record developed in our consideration of IOU appeals of the Executive Director's Notice of Intent to Release Aggregated Data supports the importance of long-term contracts as a means of reducing vulnerability to short-term fluctuations in the market.[22] In the context of evaluating the possible impacts of release of the aggregated data, staff witnesses considered the effects of long-term contracts. The testimony of the staff witnesses clearly demonstrated that long-term

[19] *Integrated Energy Policy Report 2004 Update (2004 Energy Report Update)*, California Energy Commission, publication 100-04-006CM, November 2004, p. 6.

[20] When we speak of 'retiring' these aging power plants, we are specifically referring to the aging steam boiler units included in the list in Appendix AA. The orderly process for retiring the aging units may include replacing them with new generating units at or near the same site.

[21] 5/9/05 RT, p. 107.

[22] Following the release of the Executive Director's Notice of Intent, the three IOUs appealed the proposed release of some of the aggregated data tables. The appeals were initially scheduled to be heard by the Energy Commission at its July 13, 2005 business meeting, with written testimony due by July 8. Following submission of the written testimony by Energy Commission staff and the three IOUs, the IOUs requested the ability to file rebuttal testimony. As a result, consideration of these appeals was postponed until August 24, 2005, with rebuttal testimony due on August 12. Staff, the IOUs, the Independent Energy Producers Association, and four energy service providers acting collectively, all filed rebuttal testimony. The Energy Commission allowed cross examination of the various witnesses during the August 24, 2005, business meeting. The Energy Commission then allowed parties to file post-hearing briefs by August 31, then voted to deny the appeals and uphold the Executive Director's Notice of Intent at the September 7, 2005, business meeting. The IOUs filed an appeal of that decision in Superior Court on October 17, 2005. All of the materials considered as part of this appeal are available on the Energy Commission's web site at: [http://www.energy.ca.gov/2005_energypolicy/documents/index.html#082405]

contracts reduce exposure to spot market price risks.[23] Staff pointed out that they also have other benefits by encouraging construction of new generation.

In sum, the most important action the CPUC can take in the 2006 procurement proceeding is to compel the IOUs to enter into long-term contracts, particularly contracts with renewable facilities. Long-term contracts will encourage development of new conventional and renewable resources, both reducing reliance on aging, less efficient plants and providing important gas-price hedging advantages. The result will be a more reliable market, with environmental and economic benefits accruing to all utility customers.

3.1.2. Renewable and Combined Heat and Power Resources

The *Energy Action Plan* priorities are well known. These priorities identify renewable and distributed generation resources as the preferred generation technologies for use in meeting electricity needs, after efficiency and demand response.[24] However, in the *Draft Energy Report*, the Energy Commission expresses significant concerns about the state's ability to ensure development of an adequate amount of renewable and distributed generation – particularly cogeneration – resources.

In addition to the previous discussion of long-term contracts, there was a significant volume of testimony in this proceeding regarding the need for standardized contracts. A number of representatives of the renewable industry discussed the difficulty associated with negotiating individual terms for each renewable contract.[25] The Energy Commission recommends that the CPUC establish standard contract terms in order to decrease the delays associated with negotiating renewable resource contracts.

The *Draft Energy Report* also addresses issues associated with the deployment of distributed generation (DG) resources. During the 2005 Energy Report proceeding, the Committee devoted considerable effort to exploring options to encourage development

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[23] *See*, e.g., Rebuttal Testimony of Energy Commission Staff, Attachment A.

[24] EAP II, p. 2.

[25] See, e.g, 5/9/05 RT, pp. 104, 105, 111, 122.

of combined heat and power (CHP) resources.[26] As part of this effort, the Committee held a workshop on April 28, 2005, to explore CHP issues. Information presented at the workshop, as well as written comments filed in the 2005 Energy Report docket, provides extensive arguments on why the state should increase its efforts to accelerate the development of these resources. In fact, the recently adopted EAP II specifically calls identifies support for CHP as an important part of the *Energy Action Plan*.[27]

The consultant study presented at the CHP workshop evaluated both base case and high deployment scenarios.[28] The base case scenario would result in total benefits over the 15-year forecast period of 400 trillion Btu in energy savings, approximately $1 billion in reduced facility operating costs, and 23 million tons of reduction in CO_2 emissions.[29] Under the high deployment scenario, these benefits reach 1,900 trillion Btu in energy saving, $6 billion in reduced costs, and CO_2 reductions of 112 million tons. These are compelling figures and support significant additional emphasis on CHP resources as an important part of California's energy future.

At the Committee hearing on CHP, a number of entities provided presentations that addressed CHP issues. Several discussed the difficulties associated with interconnection for these facilities, focusing specifically on the CA ISO tariff. David Dyck of Valero Energy Corporation noted that compliance issues associated with the ISO tariff are very significant. While electricity generation is not Valero's primary business, it has the permits and space to add a second cogeneration unit, but they are stuck in limbo because PG&E won't purchase their power unless they sign a master services agreement with the CA ISO.[30] Michael Alcantar of the Cogeneraion Association of California/ Energy Producers and Users Coalition (CAC/EPUC) expressed similar

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[26] CHP, also know as cogeneration, differs from other DG resources in that it tends to be installed in fairly large systems; in fact 90 percent of the installed CHP facilities in the state (representing approximately 9,000 MW) have a capacity of 20 MW or greater. (*Assessment of California CHP Market and Policy Options for Increased Penetration*, April, 2005, p. viii.)

[27] EAP II, pp. 7, 8.

[28] *Assessment of California CHP Market and Policy Options for Increased Penetration*, April, 2005, CEC-500-2005-060D.

[29] *Id*. at p. ix.

[30] Dyck 4/28/05 RT, pp. 34-36.

concerns. He noted that the primary purpose of Watson Cogeneration, a 410 MW facility at the BP refinery in Carson, is to ensure that the refinery has process steam, with electricity as a by-product. These cogeneration plants "are fundamentally steam plants, but from the CA ISO perspective you're a power plant."[31] Barry Lovell, representing Berry Petroleum, discussed its experiences exploring construction of two new cogeneration units during the 2000-2001 energy crisis that would have totaled 90 MW. He noted that they were required to sign with the CA ISO as a participating generator. "You end up signing a very simple 13-page document that basically says that you're going to comply with every [CA] ISO tariff that will ever be written. And many of them are confidential and you can't even see them. So for someone who's not in the power generation business, this is kind of a scary process."[32]

Others identified problems in contract negotiations.[33] Rod Aoki of CAC/EPUC testified at the July 25, 2005, Committee workshop on implementing California's loading order for electricity resources that California needs to ensure that existing CHP capacity be retained. "CHP contracts are expiring at a significant rate over the next five to seven years" - 1,000 MW by 2008 and 1,800 MW by 2010.[34] Mr. Aoki also pointed out that the benefits existing CHP facilities are providing will be lost if contract negotiations are not successful. He offered the example of an existing 300 MW facility in California that had been in negotiations for quite some time and whose current contract was set to expire on August 30, 2005. The facility owner was completely uncertain about what to do.[35] Other existing large CHP facilities are trying to make decisions on equipment upgrades and replacements; greater certainty about long term contracts with the utilities to allow these upgrades and replacements take place.[36]

The Energy Commission recognizes that these facilities are quite different from traditional merchant plants, and that the IOUs are reluctant to include them in their

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[31] Alcantar 4/28/05 RT, pp. 66.

[32] Lovell 4/28/05 RT, pp. 80-81.

[33] *Id*. at 77, 81.

[34] Aoki, 7/25/05 RT, p. 207.

[35] *Id*. at 208.

[36] *Id*. at 209-210.

portfolios. However, given both the benefits that they offer and the fact that the IOUs develop portfolios with a wide range of resources with different operational profiles, the Energy Commission believes it is in the state's interest to promote these resources. The CA ISO's recent identification of a need in excess of 25, 000 MW for generation located close to load strongly reinforces this conclusion.[37]

As a result, the *Draft Energy Report* includes the following recommendations for encouraging the increased use of CHP resources to meet the state's energy needs:

- ♦ By the end of 2006, the CPUC should require IOUs to buy, through standard offer contracts, all electricity from CHP plants in their service territories as delivered at the utility's avoided cost, as determined by the CPUC in R.04-04-025.... These long-term contracts should be of sufficient length to enable CHP owners to make well-informed investment decisions while providing appropriate assurances to the Energy Commission and utilities of their availability for long-range planning purposes. At a minimum, the terms of these contracts should be ten years; however, the Energy Commission and CPUC should work together to evaluate whether these contracts should have terms with the same economic life as avoided resources.[38]

- ♦ In order for California to attain its preference for DG and CHP, the IOUs should be compensated for revenue shortfalls to the point of making them at least neutral to the deployment of DG and CHP on their respective systems. California should look at regulatory incentives to reward IOUs for promoting public- and utility-owned CHP and DG projects. Approaches such as the Earned Rate Adjustment Mechanism, which were successful in keeping IOUs revenue-neutral for energy efficiency programs, could be implemented for CHP and DG…. The CPUC should immediately develop a framework for providing DG and CHP incentives to utilities to be implemented by the end of 2006.[39]

- ♦ Relative to system planning, the *Assessment of California CHP Market and Policy Options for Increased Penetration* determined a realistic goal of 5,400 MW of CHP by 2020, which is attainable if policies recommended here are implemented. By the end of 2006, the Energy Commission and CPUC should work collaboratively to translate this goal into yearly procurement targets for IOUs. The Energy Commission and CPUC should establish mechanisms in the procurement process to ensure that existing CHP systems continue to be a baseload portion of the IOUs' portfolios. These mechanisms should rely on

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[37] *Local Capacity Technical Analysis: Overview of Study Report and Final Analysis,* California Independent System Operator, September 23, 2005.

[38] *Draft Energy Report*, p. 66.

[39] *Id.* at 66-67.

the cost/benefit methodologies currently being established in CPUC proceeding R.04-03-017 to ensure that California pursues the projects that provide net societal benefits.[40]

- Fourth, the state should use CHP to effectively provide air quality and greenhouse gas reduction benefits while reducing transmission and distribution congestion. CHP facilities are located in local load centers where system operators struggle to assure adequate local reliability. In addition, CHP provides significant resources during peak demand periods which can help mitigate operational problems associated with meeting state electricity peaks. To maintain the environmental and transmission benefits, California should explore production credits for CO_2 reductions provided by CHP, and by the end of 2006, the CPUC should direct utilities to provide transmission and distribution capacity payments for CHP projects.[41]

These steps should help resolve many of the difficulties in negotiating contracts identified by the participants in the 2005 Energy Report process. Finally, the CPUC should require IOUs to offer CA ISO scheduling services at cost to their CHP customers to reduce the barriers created by the CA ISO tariff. Implementation of these recommendations should help ensure that the state's objectives of promoting CHP and harnessing its significant financial and environmental benefits are achieved.

3.2. Portfolio Performance and Least-Cost, Best-Fit Criteria

The CPUC stated in its December 2004 resource procurement decision that it will rely upon a portfolio approach to balance obtaining adequate resources and procurement.[42] IOUs currently employ least-cost, best-fit criteria when selecting bids from their solicitations. These criteria ostensibly ensure that selected bids match the base load, peaking, and other physical characteristics of system needs. The Energy Commission has significant concerns with the current application of the least-cost, best-fit criteria. Utilities have developed individual methods to calculate or weigh these criteria including resource or market value, portfolio fit, credit, viability, transmission impact, debt equivalence, and non-price terms and conditions. As stated in the *Draft Energy Report*:

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[40] *Id.* at 67.

[41] *Id.* at 67-68.

[42] D.04-12-048, p. 28.

> [The] descriptions provided by utilities about the use of least-cost, best-fit criteria are not universally transparent and require a high degree of subjective interpretation and judgment. The application of these criteria in bid selection is known only to utilities and individuals participating in PRGs.[fn][43]
>
> > fn: In its 2005 Request for Offers for renewables, Southern California Edison reserved the right to conduct the solicitation without procurement review group concurrence, subject to CPUC approval. Since all discussions with procurement review groups are confidential no one outside the procurement review group can discern whether legitimate issues were raised by members and dismissed by the utility or even the extent to which the details of the least-cost, best-fit criteria are disclosed within the group.

A recent review by the Energy Commission of evaluation criteria indicated that significant shortcomings in the market value and portfolio fit criteria that are currently being used by utilities.[44] For example, the market valuation looks at the present value of an asset compared with a market price assumption, where portfolio fit criteria compares an asset to the utility's "short" or "long" positions. While these comparisons have value when looking at a single asset, they are less valid when examining a larger portfolio because the portfolio changes the market price assumption.

The *Draft Energy Report* notes that:

> The state's energy objectives may be broader than the way IOUs define least-cost, best-fit: they also include improving security of a cost-effective supply under a range of uncertain but reasonably anticipated events, such as:
>
> - Major disruptions in supply or extreme volatility in prices of a single fuel, such as natural gas.
> - Loss of access to or extended outage of a significant portion of a single technology type, such as nuclear.
> - Adverse hydro and/or extreme temperature conditions.
>
> The Energy Commission recommends additional development of portfolio approaches and risk assessment to develop a more transparent and standardized method for determining what constitutes least-cost, best-fit. This would allow policy makers to better ensure that IOU resource selections reflect the state's interest in addressing future electricity risk and uncertainty.[45]

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[43] *Draft Energy Report*, p. 52.

[44] *Upgrading California's Electric Transmission System: Issues and Actions for 2005 and Beyond*, July 2005, CEC-700-2005-018, attachment 3, *Risk, Portfolio Theory and Transmission Planning*.

[45] *Draft Energy Report*, p. 53.

3.3. Greenhouse Gas Performance Standard

Governor Schwarzenegger has adopted aggressive greenhouse gas (GHG) emissions targets for California. For the state to meet these targets, electricity planning and procurement will need to address GHG emissions. The CPUC has taken an important first step in this direction by addressing the potential financial risk IOUs face from future GHG policies by incorporating the "carbon adder" as part of the IOU evaluation of future procurement. Further steps are likely to be implemented in the future.

In the interim, California's utility procurement policy will affect achievement of its GHG reduction goals and may be a critical driver of "clean coal" technology development in the West. California has a special interest in avoiding the severe consequences of climate change that have been identified for the state, and a compelling motivation to reduce GHGs. Without burdening interstate commerce or discriminating against particular technologies or fuels, the state should specify a GHG performance standard to be applied to all utility procurement, both in-state and out-of-state, both coal and non-coal.

The Committee held two days of workshops on August 17 and 18, 2005, seeking public comment on the technology, environmental and design permitting and operational issues associated with state imports of electricity from coal-based generating plants in the Intermountain West region. The workshop included participation from representatives of the United States Department of Energy, the State of Wyoming, the Western Interstate Energy Board, the Western Governors' Association, industry, utilities, academic research institutes, and public interest groups. This workshop highlighted the advances being made in development of clean coal technologies. Many of the participants encouraged California to play an active role in the ongoing development of these advanced technologies, while acknowledging the need to address GHG emission issues.

While more specific recommendations must await the January 2006 report of Governor Schwarzenegger's Climate Action Team, the Energy Commission recommends that any GHG performance standard for utility procurement of long-term baseload resources be set so that GHG emissions are no higher than levels achieved by a new combined-cycle natural gas turbine. Additional consideration is needed before determining what role, if any, GHG emission offsets should play in complying with such a performance standard.

At its October 6, 2005 meeting, the CPUC responded to the *Draft Energy Report* and in Chairman Desmond's letter requesting input on the proposed GHG performance standard by adopting a resolution that, in part, directed its staff:

> … to investigate adoption by the PUC of a greenhouse gas emissions performance standard for IOU procurement that is no higher than the GHG emissions levels of a combined-cycle natural gas turbine for all procurement contracts that exceed three years in length and for all new IOU owned generation. In the case of coal-fired generation, the capacity to capture and store carbon dioxide safely and inexpensively is necessary to meeting the standard;
>
> … to investigate the integration of a GHG performance standard into the PUC's existing policies regarding GHG emissions including the environmental adder, the procurement incentives framework, as well as the work of the Governor's Climate Action Team and the CEC. A critical step in this process will be to collect specific fuel type information for IOU procurement at a level of detail that will allow the State to ensure that the performance standard is met;
>
> … working with the CEC, to investigate offset policies that are designed to ensure that the Governor's GHG goals are achieved. In addition, the PUC directs Staff to consider whether an offset policy would eliminate the important benefit of mitigating financial risk to California consumers of future GHG regulation and also significantly dampen the market signal for investment in new and improved technologies for clean generation. Finally, any offset policy must include a reliable and enforceable system of tracking emissions reductions.[46]

The Energy Commission looks forward to working with the CPUC to implement a GHG performance standard as part of the 2006 procurement proceeding.

3.4. Transparency in Energy Planning and Procurement

As discussed previously in Section 2.3, the Energy Commission firmly believes that responsible and effective electricity resource planning should not and cannot exclude the public. The Energy Commission believes it is critically important to the integrity of the 2006 long-term procurement proceeding that the CPUC refrain from relying on confidential data and confidentiality agreements that allow some participants but not others to review the information that is the basis of a CPUC

[46] California Public Utilities Commission, Policy Statement on Greenhouse Gas Performance Standards, October 6, 2005, pp. 2-3.

decision. The *EAP II* also emphasizes the need for transparency in the energy planning process, stating that "we [the CPUC and the Energy Commission] pledge to remove the remaining barriers to transparency in the electricity resource procurement process in the State".[47] In addition, it says "we must streamline and make transparent all of our approval processes. . ."[48]

Two areas in which the confidentiality procedures of the CPUC are particularly troubling are in the determination of "least-cost, best-fit", and in the implementation of the renewable portfolio standard (RPS) program. Currently, determination of whether a particular resource meets "least-cost, best-fit" criteria is made entirely in secret, thus providing no information about how different attributes of projects are weighed against one another. Energy Commissioners, legislators, and members of the public have no way of knowing how least-cost, best-fit criteria are implemented for any given project. This severely undermines the credibility of these determinations; in fact, it is impossible to tell what criteria are used to approve resources procured by the IOUs. The Energy Commission has previously identified the significant benefits that accrue from the rigorous public scrutiny of data and planning assumptions and stated that when agencies cannot identify or discuss the information that underlies their decisions, they have lost the right to claim to be responsive to those who have a right to understand their decisions. We strongly encourage the CPUC to address this now, and to refrain from the use of procurement review groups, non-disclosure agreements, and other mechanisms that prohibit transparency in resource planning decisions.

We also note that the process under which RPS procurement decisions are made are similarly shrouded in secrecy. As with least-cost, best-fit determinations, such decisions do not provide any information to the public, other agencies, or the Legislature about the criteria that are used or how they are applied. The Energy Commission, which is responsible for awarding supplemental energy payments (SEPs) under the RPS program, has received no information on the costs of the RPS bids and contracts.[49] Under these circumstances, there are no assurances that the limited public

[47] EAP II, p. 2.

[48] *Id*. at 6.

[49] Geesman, 7/25/05 RT, p. 111.

funds that are available for SEPs would be expended prudently or in a manner consistent with state policy. We urge the CPUC to put a halt to this practice and increase the transparency of the SEP process. The procurement of renewable resources is an important part of the state's energy policy goals and of the *Energy Action Plan*. It is critical that both the Energy Commission and the CPUC be able to demonstrate how they are implementing these objectives.

3.5. Departing Load

One key uncertainty facing the IOUs is the degree to which load may depart from their customer base to either new community choice aggregation providers or direct access providers. A number of the participants in the proceeding stated that because of concerns about this risk, IOUs are reluctant to enter into long-term contracts.[50] Multiple parties indicated that establishing the "coming and going rules" for future direct access is the best way to reduce any remaining uncertainty about future IOU loads. The CPUC's Office of Ratepayer Advocates (ORA), SCE, PG&E, SDG&E, and TURN generally agreed that there is more uncertainty about reentry rights than there is about the departure of loads to retail sellers other than the IOUs.[51] Since utilities are the providers of last resort, the conditions for returning to IOU service were seen as the most critical element of these rules.

ORA suggested its preference for reentry would be that once customers leave the utility, they should not be allowed to return. However, they did say they were open to solutions being pursued in other parts of the country to develop capacity markets and CA ISO back-stop strategies.[52] SCE and PG&E both indicated that, while at times their companies have considered the "once you're gone, you can't return" policy, they recognize that is not consistent with what their customers want.[53] SDG&E called for

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[50] 7/7/05 RT, pp. 19, 91, 188, 189.

[51] Transcripts from the *Energy Report* Committee June 29, 2005 hearing on the IOU resource plans and the July 7, 2005 workshop on electricity policy issues.

[52] Ibid, testimony of Scott Cauchois, Office of Ratepayer Advocates.

[53] Ibid, testimony of Stuart Hemphill, Southern California Edison, and of Harold LaFlash, Pacific Gas and Electric.

reasonable switching rules to address departing load uncertainty.[54] TURN expressed concerns about the ability to enforce such a rule in a situation where the IOU is the only entity that can serve the load.[55]

Because of the need to enter into long-term contracts and encourage construction of new facilities, the Energy Commission believes it is critically important that the CPUC establish a mechanism under which the IOUs are protected from costs associated with the long-term procurement of resources for load that may subsequently change service providers. The CPUC has already indicated that it is supportive of this concept, stating:

> In general we agree that the utilities should be allowed to recover their stranded costs from all customers, including an exit fee. Such an approach best meets the [CPUC's] goals of providing "the need for reasonable certainty of rate recovery" (as required under AB 57 and noted in the June 4th ACR) as well as best ensuring that California meets its energy needs.
>
> Requiring departing customers to assume a fair share of their costs is also consistent with the [CPUC's] policy of holding captive ratepayers harmless as required by state law.[56]

The Energy Commission strongly encourages the CPUC to begin the process of establishing rules to implement these goals as expeditiously as possible so that the risk of departing load can no longer be used to justify avoidance of long-term contracts. As stated in the *Draft Energy Report:*

> The Energy Commission agrees with the CPUC's conclusion that establishing exit fees for departing load is the most equitable approach for meeting the goal for providing "the need for reasonable certainty for rate recovery" as well as ensuring that California meets its energy needs.[57] The Energy Commission believes that the CPUC policy of establishing exit fees is sufficient to eliminate the lion's share of uncertainty about departing load. The Energy Commission is troubled with IOUs using concerns over departing load to avoid securing significant long-term procurement required to meet California's growing electricity needs….

[54] Ibid, testimony of Robert Anderson, San Diego Gas and Electric.

[55] Ibid, testimony of Kevin Woodruff, The Utility Reform Network.

[56] D.04-12-048, p. 52.

[57] *Id.* at pp. 52 and 185.

> Because the remaining uncertainty about coming and going rules, especially return rights, is inhibiting investment in new generation, the Energy Commission recommends that the CPUC begin immediately to establish appropriate coming and going rules for departing load. The CPUC should establish a schedule that would provide a sound set of departing load rules by the end of 2006.[58]

4. Procedural History on Demand Forecasts and Resource Plans

4.1. Demand Forecasts

As part of the 2005 *Energy Report* process, all LSEs with annual peak demand greater than 200 MW were required to submit to the Energy Commission both retail price and electricity demand forecasts, along with supporting information.[59] LSEs with annual peak demand below 200 MW were deemed exempt for this proceeding. The Energy Commission Order required LSEs to submit their forecasts on Forms and Instructions (F&I), which were published in draft form in September 2004, and discussed at workshops on September 20 (retail price) and September 21 (demand). The Energy Commission received the LSE forecasts in February 2005.

The adopted retail price F&I directed all LSEs with a load of 200 MW or greater in 2003 or 2004 to file electricity revenue requirements for price forecast development, inputs, work papers, and related information by November 30, 2004.[60] The adopted F&I also directed all LSEs with a load of 200 MW or greater in 2003 or 2004 to file the following information by November 24, 2004:

For IOUs:

Form 1.a:	Total Electricity by Source and Revenue Requirement per Category, Bundled Customers.
Form 1.b:	Electricity Sales and Revenue Requirements by Category, Bundled Customers by Customer Class.
Form 1.c:	Electricity Sales and Revenue Requirements by Category, Bundled Customers, by Rate Schedule.

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[58] *Draft Energy Report*, pp. 48-49.

[59] *Order Adopting Demand Forecast and Price Information Forms and Instructions,* November 3, 2004.

[60] *General Instructions: Retail Electricity Price Forecast*, November 3, 2004.

For Publicly Owned Utilities:

Form 2.a: Total Electricity by Source and Revenue Requirement per Category.

Form 2.b: Electricity Sales and Revenue Requirements by Category by Customer Class.

Form 2.c: Electricity Sales and Revenue Requirements by Category by Rate Schedule.

For Energy Service Providers:

Form 3.a: Total Sales and Revenue Requirements by Category.

Form 3.b: Electricity Sales and Revenue Requirements by Category per Customer Class.

The following LSEs provided information on their revenue requirements:

IOUs:

- PG&E
- SCE
- SDG&E

Energy Service Providers:

- APS Energy Services
- Constellation NewEnergy
- Pilot Power Group
- Sempra Energy Solutions
- Strategic Energy

Publicly Owned Utilities:

- Anaheim Public Utilities Dept.
- City of Redding
- Glendale Public Service Department
- Imperial Irrigation District
- Los Angeles Dept. of Water & Power
- Modesto Irrigation District
- Pasadena Water & Power Dept.
- Riverside Utilities Dept.
- Roseville Electric Dept.
- Sacramento Municipal Utility District
- Silicon Valley Power
- Turlock Irrigation District

Energy Commission staff prepared its own forecast of electricity and natural gas demand for each of the planning areas in the state. These forecasts are based on sectoral energy consumption and peak demand models and used retail price forecasts compiled by Energy Commission staff, using the revenue requirement information filed by the LSEs. Full documentation of the staff methods for preparing the demand forecast is provided in the *Energy Demand Forecast Methods Report*.[61]

[61] *Energy Demand Forecast Methods Report* (CEC-400-2005-036, June 2005).

The adopted demand forecast F&I directed all load serving entities with a load of 200 MW or greater in 2003 or 2004 to file the following information by February 1, 2005[62]:

Form 1. Historic and Forecast Electricity Demand – annual sales and peak demand, private supply, and hourly loads

- Form 1.1 Retail Sales Of Electricity By Sector.
- Form 1.2 Net Electricity For Generation Load (Including Departed Load).
- Form 1.3 Coincident Peak Demand By Sector.
- Form 1.4 Distribution Area Peak Demand.
- Form 1.5 Peak Demand Weather Scenarios.
- Form 1.6 Hourly Loads.
- Form 1.7 Local Private Supply By Sector.

Form 2. Forecast Input Assumptions - economic and demographic assumptions and electricity rate forecasts

- Form 2.1 State or National Economic and Demographic Inputs.
- Form 2.2 Planning Area Economic and Demographic Assumptions.
- Form 2.3 Electricity Rate Forecast and Natural Gas Price Forecast.
- Form 2.4 Customer Count and Other Forecasting Inputs.

Form 3. Demand Side Management (DSM) Program Impacts and Costs (Committed and Uncommitted), including demand response and distributed generation program impacts

- Form 3.1a Efficiency Program First Year Costs and Impacts by Sector.
- Form 3.1b Efficiency Program Costs by Cost Category.
- Form 3.2 Efficiency Program Cumulative Impacts.
- Form 3.3 Renewable & Distributed Generation Program Costs and Impacts.
- Form 3.4 Demand Response Program Costs and Impacts.

Form 4 Demand Forecast Methods And Models
Form 5 Demand-Side Program Methodology
Form 6 Uncertainty Analysis

The following LSEs provided demand forecasts:

IOUs:

- PG&E
- SCE
- SDG&E

Energy Service Providers:

- APS Energy Services

Municipal utilities and irrigation districts:

- Anaheim Public Utilities Dept
- Burbank Water and Power
- City of Redding
- Glendale Public Service Department
- Imperial Irrigation District
- Los Angeles Dept, of Water & Power

[62] Information on Forms 3 and 5 relating to uncommitted resources was due on March 1, 2005.

- Constellation NewEnergy
- Pilot Power Group
- Sempra Energy Solutions
- Strategic Energy

- Modesto Irrigation District
- Pasadena Water & Power Dept
- Riverside Utilities Dept
- Roseville Electric Dept
- Sacramento Municipal Utility District
- Silicon Valley Power
- Turlock Irrigation District

The IOUs and energy service providers (ESPs) other than Pilot Power Group requested confidential treatment for much of the information provided. All three IOUs requested confidentiality for information on Forms 1.3, 1.4, 1.5 and 1.6. SCE also requested confidentiality for part of the information on Form 1.2, and SDG&E also requested confidentiality for the information in Form 2.3.[63] APS Energy Services, Constellation NewEnergy, Sempra Energy Solutions, and Strategic Energy all requested confidentiality for the information they provided on Forms 1.1, 1.3, 1.6, 2.3 and 2.4. Sempra also requested confidentiality for its information on Forms 1.4 and 1.5, and Strategic Energy requested confidentiality for Forms 4 and 6.

Based on Energy Commission regulations, the Executive Director granted a three-year term of confidentiality for IOU-supplied data on Form 1.5 demand forecast data, setting forth the peak demand resulting from "1-in-5", "1-in-10", and "1-in-20" temperature scenarios (those that can be expected to occur once in every five years, every 10 years, and every 20 years, respectively). The Executive Director also granted confidentiality for the hourly load forecast contained on Form 1.6, finding that the information can be used to calculate hourly "residual net short" forecasts, which would, by providing information about how much power the IOUs need at each hour during

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[63] *California Energy Commission Order Denying Pacific Gas and Electric Company's Appeal of Executive Director Decision Denying Confidentiality*, docket 04-IEP-1D, April 13, 2005; *California Energy Commission Order Denying San Diego Gas and Electric Company's Appeal of Executive Director Decision Denying Confidentiality*, docket 04-IEP-1D, April 13, 2005; *California Energy Commission Order Denying Southern California Edison Company's Appeal of Executive Director Decision Denying Confidentiality*, docket 04-IEP-1D, April 13, 2005; *California Energy Commission Order Denying Constellation NewEnergy Inc.'s Appeal of Executive Director Decision Denying Confidentiality*, docket 04-IEP-1D, April 13, 2005; *California Energy Commission Order Denying APS Energy Services's Appeal of Executive Director Decision Denying Confidentiality*, docket 04-IEP-1D, April 13, 2005; *California Energy Commission Order Denying Strategic Energy LLC's Appeal of Executive Director Decision Denying Confidentiality*, docket 04-IEP-1D, April 13, 2005.

the year, give sellers and buyers a negotiating advantage.[64] However, the Executive Director concluded that remaining data were not entitled to confidential treatment because the annual net peak demand data on those forms are insufficient to arrive at the hourly "residual net short" forecasts.

The Executive Director granted a three-year term of confidentiality for the ESP-supplied data on Forms 1.6 and 2.4, along with IOU distribution service area allocation of ESP forecasts on Forms 1.1 and 1.3. The Executive Director denied confidentiality for the ESPs for data on Form 1.1 showing retail sales by customer class, data on Form 1.3 showing peak demand for all customers of the ESP, information on Form 4 regarding forecast methods, and information on Form 6 relating to uncertainties.[65]

The IOUs and ESPs appealed the determination that the LSE's forecasts of annual bundled customer peak demand were not confidential. The Energy Commission upheld the Executive Director's determinations at the April 13, 2005, business meeting. SCE filed a Petition for a Writ of Administrative Mandate in Sacramento Superior Court on June 9, 2005, seeking to set aside the Energy Commission's decision regarding the confidentiality of the annual peak demand.[66] No ESPs filed an appeal of the Energy Commission's decision.

Because the dispute over the confidentiality of the annual bundled-customer peak forecasts provided by the IOUs has not yet been resolved, the Energy Commission is currently treating this information as confidential and has not considered the IOU-provided annual peak forecast in preparing the range of need. However, the dispute over the IOU-provided peak forecast does not affect the ability of the Energy Commission to publish its own staff-generated peak forecasts at either the planning area or bundled-customer levels since these staff forecasts are prepared independently

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[64] While the Executive Director's determination stated that information about hourly loads could provide a competitive advantage to bidders, the Energy Commission itself has not addressed this issue.

[65] The denial of confidentiality for information on Forms 4 and 6 only relate to Sempra Energy Solutions. Pilot Power Group and Strategic Energy did not request confidentiality for the information they supplied on these two forms; APS and Constellation NewEnergy did not provide information on these forms.

[66] No action to resolve this appeal has yet occurred; thus, for the purposes of this Energy Report cycle, the peak demand forecasts prepared by the IOUs for their bundled customers are being treated as confidential.

from the IOU-provided peak forecasts. Staff-generated peak forecasts are the basis of the demand forecast transmitted to the CPUC in this report.

The Energy Commission developed the electricity energy and peak demand forecasts for the state and for the three IOUs after consideration of separate forecasts prepared by Energy Commission staff and IOUs. These forecasts were presented at a June 30, 2005, workshop. Following discussion of the forecasts and key differences at the workshop and consideration of written comments, the *Energy Report* Committee directed staff to develop a revised set of forecasts that cover the range of likely demand for the state and for each of the IOUs. That revised forecast was published on September 26, 2005. Section 6 below discusses the different forecasts considered in June and the resulting revised forecast in more detail.

4.2. Resource Plans

As part of the 2005 *Energy Report* process, all LSEs with annual peak demand greater than 200 MW were required to submit to the Energy Commission a series of resource plans, along with supporting information. LSEs with annual peak demand below 200 MW were exempt from this requirement. Draft versions of the Forms and Instructions for these resource plans were published on December 10, 2004,[67] and discussed at a Committee workshop on December 21, 2004. Following this workshop, the Committee directed staff to publish revised F&I that provided more information on the scenarios and uncertainty analyses being requested. The initial F&I providing the reference case instructions were adopted by the Energy Commission on January 19, 2005, and the reference case filings were due March 1, 2005.[68] The supplemental instructions for the scenarios and uncertainty analyses were adopted March 2, 2005, and these filings were due on April 1, 2005.[69]

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[67] *Proposed Electricity Resource and Bulk Transmission Data Requests*, California Energy Commission Staff Report, 700-04-011, December 2004.

[68] *Forms And Instructions For The Electricity Resources And Bulk Transmission Data Submittal*, California Energy Commission, CEC-100-2005-002-CMF, January 2005; *Order Adopting Electricity Resource and Bulk Transmission Forms and Instructions*, California Energy Commission, January 19, 2005.

[69] *Supplemental Instructions and Errata to the Forms and Instructions for the Electricity Resources and Bulk Transmission Data Submittal*, California Energy Commission, CEC-100-2005-002-AD, March

Footnote continued on next page

The adopted F&I directed all load serving entities with a load of 200 MW or greater in 2003 or 2004 to file the following forms:

Form S-1: Capacity Resource Accounting Table.
Form S-2: Energy Balance Accounting Table.
Form S-3: Generic Renewable Capacity and Energy Locations.
Form S-4: Projected Qualifying Facility (QF) Energy and Costs.
Form S-5: Bilateral Contracts.

On Form S-1, all LSEs were directed to provide a reference case estimating how much power, in MW, is needed to serve monthly peak retail customer load, plus reserves and other obligations, as well as identifying how much power will come from individual electricity supply resources classified in several categories. On Form S-2, the LSEs are asked to estimate how much energy, in GWh, is needed to serve forecast needs and how much energy will come from various electricity supply resources. This capacity and energy information was required for all months of the forecast period, January 2006 through December 2016. With a few exceptions, such as hydroelectric resources and QF contracts, the LSEs were directed to provide these monthly values for individual power plants and individual contracts. Sample resource accounting tables showing the overall structure of Forms S-1 and S-2 are provided in Appendix A.

In addition to the reference case required of all LSEs, the IOUs were directed to provide a plan based on the accelerated renewables scenario recommended in the *2004 Energy Report Update*, which is aimed at PG&E and SDG&E achieving 33 percent renewable generation by 2020, and SCE, which has the greatest renewable potential in its service territory, achieving 35 percent by 2020.[70] In addition, if their reference case assumed a transmission project that upgrades the bulk transmission grid that has yet to receive regulatory approval, they were directed to provide a separate case without the transmission upgrade. SCE, whose reference case included completion of the Devers-Palo Verde No. 2 Project, and SDG&E, whose reference case included a 500-kV transmission project, both submitted cases without the upgrades. PG&E's reference case did not include a future major upgrade to the transmission system. The IOUs were also

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2005; *Order Adopting Supplemental Electricity Resource and Bulk Transmission Forms and Instructions*, California Energy Commission, March 2, 2005.

[70] *2004 Energy Report Update*, pp. 37-39.

requested to provide their preferred resource plan in addition to the reference case. All three submitted such plans, though SCE and SDG&E indicated that these were "alternate" cases that did not necessarily represent the utility's preferred future. Finally, the reference case directed the IOUs to include certain assumptions about future departing load. The IOUs were invited to submit a case with different departing load assumptions if it would provide useful planning information. PG&E included a "core/non-core" case that assumed higher levels of departing load. Each of the three IOUs provided a total of four resource scenarios, as shown in Table 1. The first three cases are similar across the IOUs, while the last is specific to each IOU.

Table 1: Resource Plan Scenarios Filed by the Investor-Owned Utilities

PG&E	SCE	SDG&E
♦ Reference case ♦ Accelerated renewables ♦ Preferred case ♦ Core/non-core	♦ Reference case ♦ Accelerated renewables ♦ Alternative case ♦ No transmission case	♦ Reference case ♦ Accelerated renewables ♦ Alternative case ♦ No transmission case

The following LSEs provided resource plans:

IOUs:
- PG&E
- SCE
- SDG&E

ESPs:
- APS Energy Services
- Constellation NewEnergy
- Pilot Power Group
- Sempra Energy Solutions
- Strategic Energy

Municipal utilities & irrigation districts:
- Anaheim Public Utilities Dept.
- Burbank Water and Power
- City of Redding
- Glendale Public Service Department
- Imperial Irrigation District
- Los Angeles Dept. of Water & Power
- Modesto Irrigation District
- Pasadena Water & Power Dept.
- Riverside Utilities Dept.
- Roseville Electric Dept.
- Sacramento Municipal Utility District
- Silicon Valley Power
- Turlock Irrigation District

The IOUs, the ESPs other than Pilot Power Group, and Imperial Irrigation District requested confidential treatment for much of the resource plan information they provided. Based on Energy Commission regulations, the Executive Director granted confidentiality for the information in Forms S-1, S-2 and S-3 for a period of three years (through the end of calendar year 2008),[71] and to the information in Forms S-4 and S-5 through the end of 2016 or to the end of the relevant contract period.[72] No appeals of these determinations were filed.

The Executive Director, pursuant to Energy Commission regulations on the treatment of confidential information (Cal. Code Regs., tit. 20, §2506), subsequently notified the IOUs and ESPs whose detailed resource plans had been designated confidential of his intent to release summary tables at a level of aggregation that would "protect the confidentiality of any underlying data that is confidential."[73] The information that the Executive Director proposed to release in these tables would be collapsed from the original LSE filings in two dimensions. First would be the quarterly and annual aggregations of the monthly values initially submitted, with maximum values provided for capacity and a sum of the monthly values for energy. Second, the

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[71] As with the similar three-year confidentiality period applied to certain of the demand forms by the Executive Director, the question of the three-year confidentiality term allowed for Forms S-1, S-2 and S-3 was not raised to the Energy Commission.

[72] Letter from California Energy Commission to PG&E (Exec. Direc. Determination) "Re: Application for Designation of Confidentiality for Electricity Supply and Uncertainties 2003-2016, Docket 04-IEP-1D," March 30, 2005; Letter from California Energy Commission to SDG&E (Exec. Direc. Determination) "Re: Application for Designation of Confidentiality for Electricity Supply and Uncertainties 2003-2016, Docket 04-IEP-1D," March 30, 2005; Letter from California Energy Commission to SCE (Exec. Direc. Determination) "Re: Application for Designation of Confidentiality for Electricity Supply and Uncertainties 2003-2016, Docket 04-IEP-1D," March 30, 2005; Letter from California Energy Commission to APS Energy Services (Exec. Direc. Determination) "Re: Application for Designation of Confidentiality for Electricity Supply and Uncertainties 2003-2016, Docket 04-IEP-1D," May 26, 2005; Letter from California Energy Commission to Constellation NewEnergy (Exec. Direc. Determination) "Re: Application for Designation of Confidentiality for Electricity Supply and Uncertainties 2003-2016, Docket 04-IEP-1D," April 28, 2005; Letter from California Energy Commission to APS Energy Services (Exec. Direc. Determination) "Re: Application for Designation of Confidentiality for Electricity Supply and Uncertainties 2003-2016, Docket 04-IEP-1D," May 26, 2005; Letter from California Energy Commission to Sempra Energy Solutions (Exec. Direc. Determination) "Re: Application for Designation of Confidentiality for Electricity Supply and Uncertainties 2003-2016, Docket 04-IEP-1D," April 27, 2005; Letter from California Energy Commission to Strategic Energy (Exec. Direc. Determination) "Re: Application for Designation of Confidentiality for Electricity Supply and Uncertainties 2003-2016, Docket 04-IEP-1D," April 28, 2005.

[73] *Energy Commission Executive Director Notice of Intent to Release Aggregated Data*, June 3, 2005, p. 1.

proposed aggregation would collapse the resource specific information such as individual power plants or individual contracts into general resource categories such as utility-controlled fossil resources or other bilateral contracts. These aggregation tables would be prepared for IOU bundled customers and separately for all customers in a larger "planning area" that includes ESPs and POUs. The three IOUs separately appealed different portions of the proposal, and parties prepared and filed direct and rebuttal testimony. Following a hearing at the August 24, 2005, business meeting, the Energy Commission upheld the Executive Director's proposal at its September 7, 2005, business meeting.[74] On October 17, 2005, the three IOUs jointly filed a Petition for a Writ of Administrative Mandate in Sacramento Superior Court seeking to set aside the Energy Commission's decision.

In June, 2005, Energy Commission staff published those aggregated tables that none of the IOUs appealed.[75] This report was published in support of the June 29, 2005, committee hearing on the IOU resource plans. The following aggregated tables were published for each IOU for each of the four resource plan scenarios that were filed:

- Annual planning area capacity tables.
- Annual planning area energy tables.
- Annual bundled-service customer energy tables.

The remaining tables (annual bundled-service customer capacity and all quarterly tables) will not be published unless the dispute with the IOUs is settled in a manner that establishes that the information at that level of aggregation is not confidential.

5. Construction of the 'Range Of Need'

In the March ACR, President Peevey noted that the Energy Commission would develop a transmittal report that would identify the likely range of statewide and IOU-specific need, discuss issues relevant to these determinations, respond to participant

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[74] *Commission Order Denying Appeals of San Diego Gas and Electric Company, Southern California Edison Company, and Pacific Gas and Electric Company of the Executive Director's Notice of Intent to Release Aggregated Data,* docket 04-IEP-1D, September 7, 2005.

[75] *Resource Plan Aggregated Data Result* (CEC-150-2005-001, June 2005).

comments, and discuss how the Energy Commission reached its decisions.[76] President Peevey made clear the CPUC's intention to rely on determinations made in the 2005 Energy Report proceeding regarding the range of need.

The Energy Commission has reviewed all of the publicly available demand forecast and resource plan information and the comments from the parties. Key Committee workshops and hearings and related staff reports considered in developing the range of need are shown in Table 2 below.

This section provides an overview of the method that the Energy Commission, after review of this record, used to construct the range of need. A more detailed discussion of specific issues raised in developing the range of need is included in the following sections.

[76] President Peevey ACR, R.04-04-003, March 14, 2005, p. 7.

Table 2: Key Hearings and Workshops

Hearing/ Workshop	Topic	Paper/ Report	Short title
Hearing June 29, 2005*	IOU Resource Plans	*Investor-Owned Utility Resource Plan Summary Assessment*	*RPSA Report*
		Resource Plan Aggregated Data Results	*Aggregated Tables Report*
Hearing June 30, 2005*	Demand Forecasts	*California Energy Demand 2006-2016 - Staff Energy Demand Forecast, Staff Draft Report*	*Staff Draft Forecast*
		Energy Demand Forecast Methods Report	*Methods Report*
		Electricity Demand Forecast Comparison Report	*Comparison Report*
		California and Western Electricity Supply Outlook Report	*Western Supply Outlook*
Workshop July 7, 2005	Electricity Issues and Policy Options	*No staff papers or reports for this workshop*	
Workshop July 11, 2005	Energy Efficiency Electricity Policy Options and Issues	*No staff papers or reports for this workshop*	
Workshop July 25, 2005	Loading Order	*Implementing California's Loading Order for Electricity Resources*	*Loading Order Report*
Hearing July 26, 2005	California and Western Electricity Supply Outlook	*California and Western Electricity Supply Outlook Report*	*Western Outlook Report*
Hearing October 7, 2005*	Revised staff demand forecast (and *Draft Energy Report*)	*California Energy Demand 2006-2016 - Staff Energy Demand Forecast Revised September 2005*	*Revised Staff Forecast*

* - In the notices for these hearings, the Committee offered parties the opportunity to conduct cross examination on the use of models. No parties asked to conduct cross examination

5.1. Use of Revised Staff Demand Forecast

Following the June 30, 2005, hearing on demand forecasts, the Committee directed staff to prepare a revised forecast, which staff published in September, 2005.[77] This forecast includes a base case that incorporates various updates and corrections as specified by the Committee. The revised forecast report also presents high and low cases that incorporate the different assumptions about economic, demographic, and energy intensity trends that were key to the differences between the staff draft forecast and the forecasts filed by the LSEs. The differences between the staff draft forecast and the LSE forecasts and the Committee's direction for developing the forecast ranges are discussed in more detail in Section 6 below.

The Energy Commission is adopting the staff revised forecast as the starting point for determining the range of need. This forecast provides both annual peak and energy forecasts for the period 2006 through 2016 on planning area, service area, and bundled-service customer levels. The IOU distribution service area includes both bundled and direct access customers, while the forecast planning areas for the IOUs generally correspond to the geographic areas that each IOU assesses in the transmission planning process, thus also including POUs. Staff prepared the forecasts at the planning area level. As described in the revised staff forecast report, the forecasts were then disaggregated to the service territory and bundled-service customer level.[78] For both the energy and capacity forecasts for IOUs, the Energy Commission is using the bundled-service customer disaggregation as the starting point for the range of need.

The revised forecast includes a base case along with a high and low forecast. These three forecasts provide the variation that defines the 'range' of need for each utility.

As discussed above, the forecasts incorporate efficiency and demand response programs for which funding has already been approved, such as the efficiency programs for 2006 through 2008. Efficiency and demand response programs for which

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[77] *California Energy Demand 2006-2016, Staff Energy Demand Forecast, Revised September 2005 (Revised Staff Forecast)*, California Energy Commission Staff Final Report, CEC-400-2005-034SF-ED2.

[78] *Id.* at 1-4.

program funding is not yet authorized should be considered as part of the future resource mix though they are not included within the demand forecasts. Alternative accounting processes yielded substantial confusion, such as SDG&E included long-term (post-2008) energy efficiency program impacts in its demand forecast.

5.2. Treatment of Departing Load

In the *2005 Energy Report* proceeding California's IOUs identified the risk of load departing to ESPs due to establishment of core/ non-core market rules, community choice aggregators (CCA),and POUs as their single greatest source of uncertainty in planning for and procuring future resources. Utilities argued that unless this issue is ultimately decided, they cannot engage in significant long-term procurement since they cannot accurately predict the amount of load they may lose. Their concern is that if a significant portion of their load migrates to a different supplier they could end up over-procuring resources and incur the stranded costs of those resources. As discussed above, the *Draft Energy Report* recommends that the CPUC promptly establish appropriate coming and going rules for departing load to address this uncertainty.

The resource plans filed by the IOUs in this proceeding made various assumptions about the level of departing load that they would face in the future. The resource plan forms and instructions directed IOUs to assume no additional migration between IOU and direct access services in the reference case and to assume a modest amount of community choice aggregation and POU departing load reaching between 4 percent and 10 percent by 2013.

The IOUs were also directed to report on the impact of other key uncertainties in addition to departing load. Uncertainties about resource portfolios include availability of large existing units (nuclear units and the Mojave coal-fired power plant),; transmission upgrades; compliance options for meeting the RPS annual energy procurement obligations; and impact of a GHG adder on bid evaluation. The IOU responses generally recommend a mix of short-, mid- and long-term contracts along with procurement flexibility as the preferred strategy.[79] Both SCE and SDG&E

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[79] The IOU responses are summarized in the *Revised Investor-Owned Utility Resources Plan Summary Assessment (RPSA Report)*, California Energy Commission Staff Report, CEC-700-2005-014, June 2005, pp. 95-101.

recommended that uncertainties would be reduced by the addition of their proposed bulk transmission connections to the Desert Southwest.

PG&E used the same planning area demand forecast in its four resource plan scenarios, which varied chiefly on the demand side by the amount of departing load. Compared with the reference case, PG&E's bundled-service energy requirements were 12 percent lower in the preferred case (which it also used for its accelerated renewables case) and 17 percent lower in the core/non-core case in 2016.

SCE filed three resource cases to demonstrate the impact on future resource needs of Energy Commission-directed assumptions: the reference case both with and without the Palo Verde-Devers No. 2 transmission project and the accelerated renewable case. All cases used the same planning area base demand forecast, which assumed that load for Cerritos was departing. Compared with the reference case and accelerated renewables case, SCE's bundled service energy requirements were 9 percent higher in its alternate case in 2016 because that case assumes no CCA.

SDG&E filed three additional resource cases to demonstrate the impact on future resource needs of an Energy Commission-directed reference case: an alternative case without CCA departing load, an accelerated renewable case, and a no major transmission interconnection case. Planning area load forecasts were the same for all cases, with the alternative case having a 4 percent higher energy forecast for bundled service load due to lack of CCA departing load.

PG&E advocated using its preferred case, with its increased levels of departing load as the basis for resource acquisition rather than the more limited loss of load in the reference case. "PG&E has designed a portfolio to minimize the risk of stranded costs should PG&E experience substantial bundled-load departures in the future."[80] PG&E's approach is to reduce the risks of stranded costs. "Consistent with its long-term plan of July 2004, PG&E anticipates procuring long-term resources to meet its minimum expected future requirements to minimize the likelihood of incurring potential stranded costs. For levels of demand above this amount PG&E intends to procure shorter-term resources."[81] PG&E acknowledges the risk of under-procurement:

[80] PG&E April 1 filing, pp 4-5.

[81] *Id.* at 12.

Given the assumptions made on Demand Response, and CCA and non-core load migration there is a risk that procurement anticipated in the preferred portfolio may not be sufficient to meet actual requirements. Should there be less customer departure, higher load growth, or less Demand Response in the early years of the plan (up to 2010), PG&E would seek to contract with existing generation under short-term contracts to balance its requirements. Sustained loads above expected amounts after 2010 could be met by re-contracting with existing resources with expiring contracts or contracting with new resources. Conversely, if CCA or non-core departures are greater or if energy efficiency is more successful than assumed, short-term contracts would be allowed to expire when their terms are complete.[82]

PG&E recommends that the Energy Commission resist temptation to be overly prescriptive in its recommendations to the CPUC since procurement planning is an ongoing and dynamic process and resource plans need to be flexible to respond to changing conditions. Going forward, PG&E anticipates these changes: new resource adequacy requirements, CCA implementation rules, new legislation, a ballot measure on direct access and utility service, and future details on CA ISO market redesign.[83]

In their own cases, SCE and SDG&E preferred to have the flexibility to plan for no new departing load, though not a return to direct access. Generally, SCE warned that procurement based on resource plans with speculative assumptions entails reliability and price risks. SCE did not file a preferred plan because of the uncertainty associated with its customer base.

Since the CPUC is still determining the rules and processes for the formation of CCAs in R.03-10-003, there is currently insufficient information available to accurately assess which cities and counties may apply for CCA status. SCE does not currently have any conclusive evidence upon which it can make a reasoned assessment for planning purposes of the amount of departing load that may be experienced. Including speculative estimates for departing load in connection with CCAs and municipilization is risky for resource planning purposes. Insofar as any scenario is used to establish procurement limits, speculative assumptions concerning possible load migration could lead to reduced reliability and increased ratepayer costs.[84]

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[82] *Id.* at 16.

[83] La Flash, 6/29 TR at p. 12-13

[84] SCE April 1 filing, pp. 5-6

SDG&E took issue with departing load assumptions required in the various resource cases and requested that: "In issuing the final [*Energy Report*], the [Energy] Commission should expressly recognize that certain forecasts contained in the Report do not necessarily constitute the forecasts that should be used for resource planning purposes."[85]

SDG&E explained its position in its April 1 filing:

> "SDG&E believes it is not only prudent but mandatory for the local utility to plan for its entire existing load until a firm and binding commitment is made by a CCA and other required elements of the CPUC's CCA program have been fully implemented. This *resource planning assumption* does not mean that SDG&E opposes CCA or that SDG&E's Resource Plan cannot be adjusted should CCA load depart; rather, for *resource planning purposes* and to ensure that the utility continues to meet its obligation to serve and provide cost-effective, reliable electric service, at this time a no CCA departure assumption is the best course."[86]

In the June 29 hearing on the IOU resource filings, parties discussed the implications of departing load uncertainty on resource planning. Scott Cauchois, ORA, agreed it is difficult for the IOUs to predict what load will depart or return. He said that if one speculates that the CPUC will make the IOUs whole as promised, then there's little risk to the IOU associated with load departing. ORA is more concerned with the uncertainty of conditions under which existing and future departing load would return to IOU service compared with the potential problems of stranded costs. Would costs of serving the returning load be imposed on bundled customers or just the returning load? Because the conditions governing returning load are not established, IOUs can't really know now what risks they face. But their procurement can't ignore the possibility of load returning since they do have the obligation of being the provider of last resort.[87]

Stu Hemphill, SCE, agreed that under procurement due to uncertainty in returning load is more of a problem than over procurement. The retail market structure has to be defined before the wholesale market structure/procurement mechanisms can

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[85] SDG&E, July 22 comments, pp. 1-2

[86] SDG&E April 1 filing.

[87] Cauchois, June 29 TR at. 118-119.

be expected to "unfold."[88] SCE has presented proposals on coming and going rules in the CPUC record.[89]

Hal LaFlash of PG&E also agrees that stranded costs from over-procurement are a financial issue while under-procurement can make the lights go out. PG&E thinks the stranded cost and exit fee protections are very important, but they still are trying to be responsible about minimizing stranded costs.[90]

Steve Kelly, Independent Energy Producers Association (IEP), stated that the provider of last resort is really the CA ISO and that direct access load returning to IOU service is the same as the IOU under scheduling in the CA ISO's markets. Hemphill responded that the CA ISO just determined it is other LSEs who are under-scheduling not the utilities.[91] All acknowledged that the resource adequacy protocols should fix the CA ISO's under-scheduling problem in the near term, which raised the question of whether resource adequacy rules are needed for a longer term than year-ahead. Kelly claimed: "Tradeable capacity markets will go a very long way . . . to relieve some of the concerns." Hemphill said that we don't necessarily need longer than one-year resource adequacy requirements or capacity markets if the coming and going rules of retail direct access are "appropriately" structured with new investment constraints in mind—"retail structure is the defining element for this industry in California."[92]

Similar themes were raised at the July 7 electricity policy workshop regarding the need to stabilize retail market rules. Robert Anderson of SD&GE said, "if we had core/non-core settled, we would have three- and four-year contracts signed."[93] SDG&E supported customer choice, but said that three things have to happen first: fix the flaws in the CA ISO/market structure, ensure adequate supply by implementing resource

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[88] Hemphill, June 29 TR at 118 - 120.

[89] *Id.* at 131.

[90] La Flash, June 29 TR at 120-121.

[91] Hemphill, June 30 TR at 122-123.

[92] *Id.* at 127.

[93] Anderson, July 7 TR 188-189.

adequacy, and eliminate perverse price signals such as capped customer rates caused by Assembly Bill 1X (Chapter 4, Statutes of 2001, Keeley).[94]

Local Power comments for Women's Energy Matters (WEM) assert that the IOUs' resource plans don't reflect as much departing load as Local Power believes will occur, based on publicly available information. If IOU procurement is based on the reference case resource plans, the IOU will over procure, and the departing load will get stuck with the cost of the IOU stranded investment. Local Power claims that 20 percent of California IOU load is in various stages of CCA.[95]

Based on this input, the Energy Commission decided that the revised forecasts upon which resource plans should be based should not include any departing load. While this approach does leave some risk that the utilities may procure resources for a larger customer base than remains in place over time, the Energy Commission believes that once the CPUC establishes appropriate coming and going rules for departing load as it signaled it would do in D.04-012-004, the resulting financial risk to the IOUs and their ratepayers is acceptable. For the IOUs to procure based on an assumption that a significant portion of their customers will depart to other providers raises much greater reliability and adequacy risks and potential for under-procurement.

5.3. Demand Response and Energy Efficiency

Demand response and energy efficiency are the top resources in the loading order. The CPUC and Energy Commission are both dedicated to ensuring that these resources be developed to the maximum extent feasible. In constructing the range of need below, the Energy Commission has included in the demand forecasts the efficiency programs for the years 2006 through 2008, whose funding the CPUC has approved. Efficiency programs for 2009 and beyond, for which the CPUC has not yet approved funding, are not included in the demand forecast. Rather, these are included in the resource plans, with the expectation that the CPUC will approve future utility programs to assure that the level of efficiency procured is optimized. The current

[94] Sakarias, July 7 TR 128-132.

[95] Paul Fenn, Local Power comments for Women's Energy Matters, June 28, 2005, p. 2, 3.

targets for efficiency are identified as part of the resource mix the IOUs will use to meet the identified need.

The Energy Commission recommends a similar approach for demand response as for energy efficiency, with demand response programs incorporated into the future Energy Commission demand forecasts as funding is approved. Targets for future programs that have not yet been funded are identified as part of the resource mix the IOUs are expected to use to meet identified need.

The term "demand response" encompasses a variety of programs, including traditional direct control (interruptible) programs and new price-responsive demand programs. A key distinction is whether the program is dispatchable. Dispatchable programs such as direct control, interruptible tariffs, or demand bidding programs, have triggering conditions that are not under the control of and cannot be anticipated by the customer. Energy or peak load saved from dispatchable programs is treated as a resource and is therefore not accounted for in the demand forecast, whether resulting from an existing funded program or a speculative program conceived to satisfy overall demand response goals created by D.03-06-032. Nondispatchable programs are not activated using a predetermined threshold condition but rather allow the customer to make the economic choice whether to modify usage in response to ongoing price signals. Impacts from committed nondispatchable programs should be included in the demand forecast.

At this time all existing demand response programs are dispatchable programs that have some form of triggering condition. Although the utility or CA ISO may not have direct control, the customer only has the opportunity to participate in the program when the program operator has called an event, either because of high market prices or resource scarcity. Therefore, no demand response impacts are counted in the demand forecasts adopted in this proceeding. If appropriate demand response tariffs are instituted, then their impacts will be incorporated in future demand forecasts.

These existing interruptible programs are one of the resources that the IOUs can call on at times of peak demand when the supply/ demand balance is tight. Consistent with the counting conventions being established in the CPUC's resource adequacy proceeding, the Energy Commission is including the capacity covered under these programs as a supply resource when calculating the capacity supply/ demand balance in the need tables.

5.4. Evaluation of Resource Plan Information

As previously indicated, the utility resource plans included detailed information on their existing and planned resource base. Each of the IOUs submitted four separate resource plan scenarios. Three of the four scenarios were common to the three IOUs: a reference case specified in the forms and instructions, a "preferred" or "alternate" case developed by the utility, and an accelerated renewables case. For PG&E, the fourth scenario was a core/non-core case. For SCE, the fourth assumed that the Devers-Palo Verde No. 2 line did not come into service. For SDG&E, the fourth assumed that the generic 500-kV transmission line included in the other cases did not come into service.

Two general comments are necessary to describe how resource plans have been evaluated. First, no monthly or quarterly data was made public, so the Energy Commission worked only with annual data. Second, differences among the scenarios on the demand side (e.g. level of departing load assumed) are not considered because the Energy Commission has decided to use the revised staff forecast as the basis for the demand numbers in calculating the range of need.

In evaluating the resource plan energy data for calculation of the range of need, the Energy Commission used the tables of annual aggregated energy data for the IOU bundled service customers for the years 2009 through 2016, as published in October, 2005, in the revised *Aggregated Tables Report*, which included some minor corrections to the original tables.[96]

On the capacity side, the Energy Commission had to be selective due to confidentiality constraints. Two sources of public capacity data were included in the record. First, each of the IOUs provided a public table with a limited amount of information on the annual capacity of some key resources for the years 2009 through 2016 when they filed their resource plans in early 2005.[97] This information included the annual peak capacity of utility controlled fossil, nuclear and hydro resources, along with the peak capacity for each of the Department of Water Resources (DWR) contracts

[96] *Resource Plan Aggregated Data Results (Aggregated Tables Report)*, California Energy Commission Staff Paper, CEC-150-2005-001, June, 2005.

[97] The public tables filed by the three IOUs for capacity and energy resources were published in Appendix B of the *RPSA Report.*

assigned to that IOU. With the exception of the DWR contracts, no information on contractual resources was in these public tables.

Second, the *Resource Plan Aggregated Data Results* included planning area capacity tables for the years 2009 through 2016. For each of the IOUs, the aggregated planning area tables totaled the annual capacity values provided by that IOU, by any publicly owned utilities located within their portion of the CA ISO control area, and a share of the ESP resources.[98] Because only the IOUs hold DWR contracts and QF contracts within their planning areas, the totals shown in the aggregated capacity tables for these two categories are specific to the IOU's bundled customers. For the three remaining categories of resources (renewables contracts, other bilateral contracts, and spot market/ short term purchases), these annual aggregated numbers, which include IOUs, ESPs, and POUs, are the only information in the public record on the capacity values. Because none of the POUs requested confidentiality for the level of data shown in the aggregated tables, the Energy Commission intends in the final *Transmittal Report* to subtract the POU shares from the planning area capacity tables to produce a "distribution service area" version of the tables that shows the sum of the IOU data and appropriate shares of the ESP data. The Energy Commission invites comment on this plan at the November 4, 2005, hearing on this *Draft Transmittal Report*.

Interruptible load programs provide another resource available to the IOUs in meeting extreme peak demand. The IOUs included in their resource plans the amount of capacity available under existing interruptible load programs. These programs are considered part of the resource base for meeting the 15 percent planning reserve requirements under resource adequacy.

When the existing utility resource base, existing contracts, planned resources, and interruptible load programs are compared against the demand forecast on a year by year basis, an initial estimate is established of the amount of energy and capacity the utilities will need to acquire to simply meet projected demand. This supply/demand balance provides a starting point for the determination of need for each IOU, though, as

[98] The ESPs allocated their loads among the three IOUs in their demand forecast forms. These proportions were used to allocate their resources to the different IOUs planning areas.

discussed below, this value will need to be adjusted to account for the retirement of aging plants.

This supply/demand balance does not exactly match the balance suggested in the structure of forms S-1 and S-2 and used in the aggregated data tables.[99] The forms included short-term and spot market purchases as part of the total existing and planned energy. With those purchases included, a total generic resource need was calculated on forms S-1 and S-2 by subtracting the total existing and planned resources from the firm peak energy or capacity requirement. In calculating future resources needs for this report, these short-term and spot purchases have not been included in the existing and planned resource mix. The equivalent of the supply/demand balance calculated here would be the sum of the short term and spot market purchases and the generic resource needs submitted to the Energy Commission in the resource plan filings.

In addition, the Energy Commission has also evaluated the public aggregations of the resource plan information provided by the LSEs, along with staff's assessment of the degree to which those plans comply with the state's policy guidance, and the comments received on these topics. As discussed below, the Energy Commission has identified amounts of preferred resources (efficiency, demand response, and renewables[100]) that the utilities should consider as the first step in meeting their resource needs. The IOUs should tailor their procurement of other resources on the assumption that at least these preferred levels of loading order resources will be achieved. The Energy Commission expects that direction to the utilities in obtaining these loading order resources will not necessarily come from the 2006 long-term procurement proceeding itself, but from related proceedings such as R.01-08-028 on energy efficiency, R.02-06-001 on demand response, and R.04-04-025 on the RPS. Thus, the procurement direction given to the IOUs in the 2006 long-term procurement proceeding needs to be designed to automatically adjust when other proceeding change the preference levels for loading order resources.

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[99] *Aggregated Tables Report.*

[100] Distributed generation is also one of the preferred resources, but no targets have been set for the IOUs. As discussed above, the Energy Commission recommends that IOU-specific targets be established by the Energy Commission and CPUC by the end of 2006. Once those targets are established, the amounts should be included in the preferred resource totals.

The Energy Commission notes that the CPUC included strong support for the loading order resources in its procurement decision last year:

> As stated above, following the "loading order" contained in the EAP is the first priority for IOU resource procurement, meaning that [energy efficiency] and demand-side resources should be employed first. When these opportunities are captured, renewable generation is to be procured to the fullest extent possible – whenever an IOU issues [a request for offers (RFO)] for generation resources, it must be prepared to defend its selection of fossil generation over renewable generation offers. In other words, selection of renewable generation is the rebuttable presumption guiding IOU generation procurement.[101]

Such policies as the "rebuttable presumption" in favor of procurement of new renewable resources included in the CPUC's D.04-12-048 or the establishment of higher energy efficiency goals in the future could result in higher levels of procurement of these resources and correspondingly lower levels of additional undesignated need.

5.5. Inclusion of Increment for Addressing Aging Power Plants

In the *Draft Energy Report*, "the Energy Commission recommends that the state's utilities undertake long term planning and procurement that will allow for the orderly retirement or repowering of the aging power plants in [the *2004 Energy Report Update*] study group."[102] This study group included only natural gas-fired power plants of 10 MW or greater that were built before 1980. Peaking plants were excluded, as were any plants known at the time to be scheduled for retirement in the near term. Power plants in this pool are listed in Appendix AA, along with their capacities and average generation during the years 2002 through 2004. Excluding the plants in the study group that are owned by POUs, this pool includes 50 power plants.

Because most of these plants have been relied upon in recent years primarily to meet peak demand, the Energy Commission recommended in the *2004 Energy Report Update* that the state's utilities "work aggressively to implement demand response programs to attain the 2007 statewide goal of reducing peak demand by 5 percent."[103] To the extent that these plants can be replaced by demand response programs,

[101] D.04-12-048, p. 77.

[102] *Draft Energy Report*, p. 151.

[103] 2004 Energy Report Update p. xvi.

efficiency programs, renewable resources, CHP, and an appropriate level of conventional power plants, the state will see significant benefits in terms of reliability, reduced reliance on natural gas, reduced GHG emissions, and other environmental benefits.

To facilitate the retirement of these aging power plants, the Energy Commission has apportioned these 50 plants to the three IOUs based on their physical location, along with their existing capacity and the average energy produced in 2002 through 2004. In order to ensure that sufficient investment takes place in the next round of procurement to provide for the orderly replacement of the retiring plants with new resources, the Energy Commission is including the full amount of the existing capacity and average energy generation of these plants for 2002 through 2004 in the identified need for each of the IOUs for 2012 and beyond.

Some time will be needed to bring any new generation on line to replace these plants, so to facilitate an orderly transition to the retirement of these plants by 2012, the Energy Commission is including a four-year ramp-up of this increment, starting with 25 percent of the utilities' share of energy or capacity in 2009, and increasing to 50 percent, 75 percent and the full share in 2010, 2011, and 2012, respectively.

5.6. Resource Needs

In the need tables, the Energy Commission is calculating an initial supply/ demand balance. For energy, this is simply the different between the total energy requirement and the total existing and planned energy resources. On the capacity side, the existing interruptible program capacity is included with the total existing and planned capacity and all of these are subtracted from the firm peak requirement to calculate the supply/ demand balance. For both energy and capacity, the increment to address the retirement of the aging plants is added in to calculate a total need, which will have to be met through some portfolio of new resources.

California has established a loading order for future resources needed to meet the state's electricity demand. As stated in Energy Action Plan II:

> The loading order identifies energy efficiency and demand response as the State's preferred means of meeting growing energy needs. After cost-effective efficiency and demand response, we rely on renewable sources of power and distributed generation, such as combined heat and power applications. To the extent efficiency, demand response, renewable resources, and distributed generation are unable to satisfy increasing energy and capacity needs, we

> support clean and efficient fossil-fired generation. Concurrently, the bulk electricity transmission grid and distribution facility infrastructure must be improved to support growing demand centers and the interconnection of new generation, both on the utility and customer side of the meter.[104]

The CPUC and the Energy Commission share a commitment to implementing the loading order. To aid this process, the Energy Commission has included identification of preferred resources on the tables showing the range of need. For energy needs, these preferred resources include uncommitted energy efficiency programs, renewable resources, and distributed generation such as combined heat and power. For capacity needs, these preferred resources include uncommitted energy efficiency programs, uncommitted dispatchable demand response, renewable resources, and distributed generation such as combined heat and power.

The Energy Commission directed the IOUs to assume in their reference case resources plans that the efficiency targets for both peak demand and energy established by the CPUC in D.04-09-060 would be met. While the targets for each IOU represented the cumulative savings expected from IOU efficiency programs starting in 2004, the IOUs were directed to include the committed savings from those programs whose funding had at the time been approved (i.e. 2004 and 2005 programs) in their retail load and sales forecasts.[105] These reference case efficiency totals reported by the IOUs are the basis for the energy efficiency numbers in the preferred resource category of the need tables. Because the CPUC has now approved funding for the energy efficiency programs for 2006 through 2008 and the resulting savings are incorporated into the revised staff forecast, the numbers reported by the utilities in their resource plan filings have been reduced by the amount of the savings through 2008. In addition, PG&E included programs for 2009, 2010 and 2011 in its demand forecast rather than as uncommitted energy efficiency, an additional 527 GWh of annual PGC energy savings and 98 MW of annual capacity savings were added into the total.

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[104] *EAP II.*

[105] *Forms and Instructions for the Electricity Resources and Bulk Transmission Data Submittal*, California Energy Commission, CEC-100-2005-002-CMF, January 2005, p. 11.

The demand response targets for capacity are calculated based on achieving the 5 percent demand response goal for 2007 and beyond, measured against the full demand in each IOU's distribution service area as direction by D.03-06-032.

Among the resource plan scenarios the Energy Commission directed the IOUs to file was one reflecting the accelerated targets recommended by the Energy Commission in the *2004 Energy Report Update*, which aim at PG&E and SDG&E achieving 33 percent renewables by 2020, and SCE, which has the greatest renewable potential in its service territory, achieving 35 percent by 2020.[106] The IOUs all filed this scenario, while generally questioning the feasibility and advisability of attempting to reach the accelerated targets. The Energy Commission recognizes that the CPUC currently lacks statutory authority to require the IOUs to procure more than 20 percent of their demand from renewable resources. While the CPUC cannot require the utilities to go beyond 20 percent, the CPUC can work to ensure that they do not prematurely buy non-renewable resources beyond 2010 to a degree that would crowd out renewables beyond 20 percent.

The Energy Commission is including in the preferred resource category the amount of renewable energy and capacity identified by the IOUs as necessary to meet the accelerated targets. The Energy Commission recognizes that these scenarios were not based on the revised staff demand forecasts and that the trajectory of that level of future purchases would not be 33 percent of demand in 2020 when using the revised staff forecast. Nonetheless, the primary purpose of identifying a preferred level of renewable resources on the need tables is to avoid procuring so much in additional undesignated resources that renewable purchases to meet future targets are precluded. Therefore, the Energy Commission considers the generic renewable resources identified by the IOUs in their accelerated renewables cases to be a useful benchmark. The Energy Commission invites comments on this approach and any recommendations for alternate approaches to determining the amount of preferred renewables to include in the need tables.

The difference between the preferred resource targets and the total need shown in the tables is the target amount that the IOUs should be planning to procure through procurement activities for undesignated needs. The Energy Commission emphasizes

[106] *2004 Energy Report Update*, pp. 37-39.

that these activities should not preclude additional energy efficiency, demand response, renewable projects, and distributed generation beyond the targets identified in the preferred resource category. The Energy Commission views those targets as the floor and not the ceiling for acquisition of efficiency, demand response, renewable resources, and distributed generation. Further, the Energy Commission is not specifying how undesignated resource needs should be acquired. We believe it is appropriate that the 2006 long-term procurement proceeding determine how resources are acquired.

5.7. Sample Range of Need

The following tables illustrate the calculation of the range of need, using numbers for PG&E for the year 2012 as an illustration. Tables showing each year and the low, base, and high demand cases are presented for each IOU in Appendix B.

The calculation of the energy need is illustrated in Table 3 and of the capacity need in Table 4. Both tables use the base forecast and PG&E's resource status for 2012 as an example. The revised staff forecast includes low and high cases as well as the base case. The difference in demand among these three cases is the basis for the variation within the range of need, while the existing and planned utility resources are the same in the three cases.

For the capacity tables, IOU-specific numbers for renewables contracts and other bilateral contracts are not currently in the public record. The tables that are included in this draft report show the planning area values that were included in the aggregated tables.[107] These numbers include data from the IOU, from ESPs in proportion to the load they serve in that service territory, and any POUs that are located within that IOUs portion of the CA ISO control area. None of the POUs within the CA ISO control area requested confidentiality for their resource plan filings. Though the Energy Commission has not published tables summarizing the resource plans for those utilities, the information in them is public.[108] In the final version of this *Transmittal Report*, the Energy Commission intends to specifically publish the data on renewables contracts

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[107] *Aggregated Tables Report.*

[108] The aggregated data tables were published by control area, with separate tables for the IOU portions of the CA ISO control area. Therefore, those tables included summary tables by control area and for the customers of SMUD, LADWP and IID.

and other bilateral contracts for those utilities, then subtract that value from the planning area totals for the resources shown in this report, which will result in capacity tables that accurately reflect resource needs at the IOU distribution service area level.

Table 3: Energy Range of Need Calculation Example

PG&E Energy for 2012, revised staff forecast base case (GWh)

		Base case	Source/explanation
	ENERGY DEMAND (GWh)		
a)	Net Energy for Bundled Customer Load	89,069	Staff revised forecast
b)	Firm Sales Obligations	413	Aggregated data tables (3)
c)	**TOTAL ENERGY REQUIREMENT**	**89,482**	***Sum of a) and b)***
	EXISTING & PLANNED RESOURCES		
	Utility-Controlled Physical Resources		
d)	Nuclear	16,797	Aggregated data tables (3)
e)	Fossil (2)	173	Aggregated data tables (3)
f)	Total Hydro Energy Supply	15,061	Aggregated data tables (3)
g)	**Total Utility-Controlled Physical Resources**	**32,030**	**Sum of d) through f)**
	Existing and Planned Contractual Resources		
h)	Total Energy Supply from DWR Contracts	1,190	Aggregated data tables (3)
i)	Total Energy Supply from QF Contracts	19,769	Aggregated data tables (3)
j)	Total Existing & Planned Renewable Contracts	528	Aggregated data tables (3)
k)	Total Energy from Other Bilateral Contracts	1,063	Aggregated data tables (3)
l)	**Total Contractual Resources**	**22,550**	**Sum of h) through k)**
m)	**TOTAL EXISTING & PLANNED ENERGY RESOURCES**	**54,580**	***Sum of g) and l)***
n)	**SUPPLY/DEMAND BALANCE**	**34,902**	***Difference of c) and m)***
o)	**Aging Plant Replacement**	**7,498**	average annual generation from the aging plants in the pool located in the service territory of that IOU for the years 2002 through 2004(4)
p)	**TOTAL NEED, INCLUDING AGING PLANT REPLACEMENT**	**42,400**	**Sum of n) and o)**

Table 3: Energy Range of Need Calculation Example (continued)

	ADDITIONAL PREFERRED RESOURCES		
q)	Uncommitted Energy Efficiency	4,204	Uncommitted energy efficiency reported by IOU, adjusted for inclusion of committed 2006-2008 programs being included in demand forecast (5)
r)	Renewables	7,890	Generic renewables report by IOU for accelerated renewables case, reported in aggregated data tables*
s)	Distributed Generation/ CHP	*Target to be developed by Energy Commission and CPUC in 2006*	
t)	**TOTAL ADDITIONAL PREFERRED RESOURCES (1)**	**12,094**	***Sum of q) through s)***
u)	**ADDITIONAL NON-DESIGNATED NEED (1)**	**30,306**	***Difference of p) and t)***

Notes:

(1) - The total additional preferred resources will increase and the additional non-designated need will decrease when DG/CHP targets are established in 2006, since a portion of the undesignated need will be designated to DG/CHP.

(2) - In its reference case, PG&E did not include any energy values for the Humboldt Bay replacement project, though it included 150 MW of capacity. The Energy Commission is including the fossil resource energy values that PG&E filed with its preferred, accelerated renewables, and core/non-core cases.

(3) - Data from aggregated data tables are based on IOU filings for the reference case, except as noted. (Source: *Resource Plan Aggregated Data Results (Aggregated Tables Report)*, California Energy Commission Staff Paper, CEC-150-2005-001, June, 2005.)

(4) - The aging plant replacement ramps up to the full share in 2012. For 2009, the value is 25 percent of the full share, for 2010 it is 50 percent, and for 2011 it is 75 percent.

(5) These values are calculated from Tables 2-3, 2-9, and 2-13 in the *RPSA Report* and IOU comments on that report. Because the demand forecast includes programs through 2008, the first-year GWh savings through 2008 are subtracted from the cumulative totals from line 1.

Table 4: Capacity Range of Need Calculation Example

PG&E Capacity for 2012, base case demand forecast (MW)

		base case	Source/explanation
	PEAK DEMAND (MW)		
a)	Peak Service Area Demand (base case) (1)	20,256	Staff revised forecast
b)	Peak Bundled Customer Demand (base case)	18,872	Staff revised forecast
c)	Reserve Margin (at 15 percent)	3,038	15 percent of b)
d)	Firm Sales Obligations	0	Aggregated data tables (4)
e)	**Firm Peak Requirement**	**21,910**	***Sum of b) through d)***
	EXISTING & PLANNED CAPACITY		
	Utility-Controlled Physical Resources		
f)	Nuclear	2,214	IOU public capacity tables (4)
g)	Fossil	150	IOU public capacity tables (4)
h)	Total Dependable Hydro Capacity	4,734	Aggregated data tables (4)
i)	**Total Utility-Controlled Physical Resources**	**7,098**	**Sum of f) through h)**
	Contractual Resources		
j)	DWR Contracts	263	IOU public capacity tables (4)
k)	QF Contracts	2,517	IOU public capacity tables (4)
l)	Renewable Contracts (2)	172	Aggregated data tables (4)
m)	Other Bilateral Contracts (2)	1,538	Aggregated data tables (4)
n)	**Total Contractual Resources**	**4,491**	**Sum of j) through m)**
o)	**TOTAL EXISTING & PLANNED CAPACITY**	**11,588**	***Sum of i) and n)***
p)	**Existing Interruptible/ Emergency Programs**	**374**	IOU public capacity tables (4)
q)	***SUPPLY/DEMAND BALANCE***	***9,948***	***Difference of e) and total of o) and p)***
r)	**Aging Plant Replacement**	**4,737**	capacity of the aging plants in the pool located in the service territory of that IOU (5)
s)	**TOTAL NEED, INCLUDING AGING PLANT REPLACEMENT**	**14,685**	**Sum of q) and r)**

Table 4 Capacity Range of Need Calculation Example (continued)

	ADDITIONAL PREFERRED RESOURCES		
t)	Uncommitted Energy Efficiency	952	Uncommitted energy efficiency reported by IOU (7)
u)	Uncommitted Dispatchable Demand Response (8)	1,013	CPUC target of 5% of service territory load shown in a)
v)	Renewables	1,017	Generic renewables reported by IOU for accelerated renewables case, reported in aggregated data tables (6)
w)	Distributed Generation/ CHP	*Target to be developed by Energy Commission and CPUC in 2006*	
x)	**TOTAL ADDITONAL PREFERRED RESOURCES (3)**	**2,982**	***Sum of t) through w)***
y)	**ADDITIONAL UNDESIGNATED NEED (3)**	**11,703**	***Difference of s) and x)***

Notes:

(1) - Peak distribution service area demand is used for calculation of the uncommitteed dispatchable demand reponse targets.

(2) - Planning area data are presented here because the IOU bundled customer data are confidential.

(3) - Total additional preferred resource will increase and the additional undesignated need will decrease when DG/CHP targets are established in 2006, since some undesignated need will be designated to DG/CHP.

(4) - Data from aggregated data tables or IOU public capacity tables are based on IOU filings for the reference case, except as noted. (Source: *Resource Plan Aggregated Data Results (Aggregated Tables Report)*, California Energy Commission Staff Paper, CEC-150-2005-001, June, 2005.)

(5) - The aging plant replacement ramps up to the full share in 2012. For 2009, the value is 25 percent of the full share, for 2010 it is 50 percent, and for 2011 it is 75 percent.

(6) - These values may include contractual resources held by the publicly owned utilities in the PG&E planning area or by ESPs.

(7) - These values are calculated from Tables 2-4, 2-10, and 2-15 in the *RPSA Report* and utility comments on the report. Because the demand forecast includes programs through 2008, the MW savings for 2008 are subtracted from the cumulative totals from line 1.

(8) - The value reflects the full 5% goal to be achieved by 2007 and beyond. The estimated impacts of the programs authorized under R.02-06-001, Critical Peal Pricing tariffs authorized by the CPUC pursuant to the applications filed in summer 2005, the portion of the DWR Demand Reserves Partnership allocated to each IOU, and other mechanisms that are eligible to satisfy the goals are included here. The difference between the goal and the sum of authorized program impacts is the amount remaining to be achieved from new programs and tariffs.

5.8. Future Adjustments to the Range of Need

The Energy Commission recognizes that some of the information used in constructing the range of need shown in the tables in this report will be out of date by the conclusion of the CPUC's 2006 long-term procurement proceeding (LTPP). The Energy Commission offers the following guidelines for when and how adjustments to the numbers would be appropriate.

In terms of the demand forecasts, the Energy Commission believes that the revised staff forecast provides the appropriate basis for the 2006 LTPP. A biennial proceeding focused upon the long-term cannot be a good source of short term demand forecasts that are updated frequently for recent historic data and near-term expectations. Such near-term demand forecasts are appropriate for many operating activities. The Energy Commission does not anticipate any conditions in which an update of the staff revised forecast for the years 2008 and beyond would be appropriate for long-term planning purposes before the *2007 Energy Report* is completed. The short-term demand forecasts that all LSEs will be using each year as part of compliance with resource adequacy requirements should be established through other proceedings. Thus, updates for the 2006 and 2007 load forecasts reported here for purposes other than long-term planning are acceptable if the IOU has been granted discretion to do so.

On the resource side, the Energy Commission notes that the IOUs have begun to fill the resource needs identified in their filings. For example, PG&E has signed a capacity and dispatchable energy contract with Duke Energy for the 650-MW Morro Bay Power Plant from 2005-2007, initiated a long-term RFO for 1,200 MW in 2008 and an additional 1,000 MW in 2010, and proposed to construct and operate the 530-MW Contra Costa 8 unit, which may defer a portion of the long-term RFO; SCE has signed renewables contracts for about 640-MW, including a 500-MW peaking solar thermal energy project; and SDG&E has signed a contract with a 300-MW peaking solar project.

The Energy Commission recommends that the CPUC direct the utilities to update their utility-controlled and contractual resource status by filing in the 2006 LTPP a listing of all contracts and other projects since January 1, 2005. This filing should clearly indicate whether these projects were included in the reference case resource plan filed at the Energy Commission during the 2005 Energy Report proceeding. The energy and capacity values of those projects can then be added to the appropriate line of the range of need tables and the resulting totals recalculated. The Energy Commission does not anticipate that any other changes to the existing and planned resource base would be appropriate.

In terms of energy efficiency and demand response, the tables are based on the Energy Commission's understanding of the implications of the adopted EAP II loading order preferences. If the CPUC formally adopts goals for any of these preferred resources in the future, these numbers should be adjusted as appropriate. For renewables, this line is the "generic renewables" that would need to be procured in the future as reported by the IOU for the accelerated renewables case. Any adjustments to either the target or the existing and planned resource base should be reflected in this line. No numbers have been included for distributed generation and combined heat and power resources. The *Draft Energy Report* notes that 5,400 MW by 2020 is a realistic goal and recommends that "by the end of 2006, the Energy Commission and the CPUC should work collaboratively to translate this goal into yearly procurement targets for IOUs." (*Draft Energy Report*, p. 67) Once these yearly targets are set, they should be incorporated into the need tables. The Energy Commission does not anticipate any other changes to the preferred resource numbers until they are review again in the 2007 Energy Report proceeding.

6. Electricity Energy and Peak Demand Forecasts

6.1. Energy Commission Draft Staff Demand Forecast

The *Staff Draft Forecast* was published on June 14, 2005.[109, 110] Table 5 summarizes the key statewide results of the June staff forecast. The staff and LSE forecasts are described in more detail in the sections below on the individual planning areas.

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[109] *California Energy Demand 2006-2016 - Staff Energy Demand Forecast (Staff Draft Forecast)*, California Energy Commission Staff Draft Report, CEC-400-2005-034-SD, June 2005.

[110] As discussed below, the draft staff forecast is not the forecast used for calculation of the range of need. The draft staff forecast and the LSE forecasts were evaluated by the parties at the June 30, 2005 hearing. Based on that hearing, the Committee directed staff to prepare a revised forecast, which is the basis of the range of need.

Table 5: Staff Draft Forecast of Statewide Electricity Demand

	Consumption (GWH)		Peak (MW)
1990	229,367		46,907
2000	262,985		53,758
2003	264,824		55,303
2008	285,867		60,878
2013	304,355		65,144
2016	314,471		67,569
Annual Average Growth Rates			
1990-2000	1.38%		1.37%
2000-2003	0.23%		0.95%
2003-2008	1.54%		1.94%
2003-2013	1.40%		1.65%
Historic values are shaded			

Source: *California Energy Demand 2006-2016 - Staff Energy Demand Forecast (Staff Draft Forecast)*, California Energy Commission Staff Draft Report, CEC-400-2005-034-SD, June 2005.

In addition to the June staff demand forecast, Energy Commission staff prepared a separate report comparing the staff forecast to forecasts provided by the LSEs.[111] This report compared the electricity demand forecasts filed by the LSEs in February, 2005, with the staff draft forecast of annual electricity use and peak demand at both the total level and at the sectoral level where possible. The staff draft forecast was presented at a planning area level. For the comparison report, the forecasts from the different LSEs were aggregated, with the forecasts provided by each IOU being combined with the portion of the forecast load for ESP customers using that IOU's distribution system and with the load for the POUs within the IOU's portion of the transmission system.[112] While the IOU bundled-customer annual peak demand is being treated as confidential pending completion of SCE's lawsuit against the Energy Commission, the LSEs agreed that the aggregated planning area annual peak demand could be made public.

[111] *Electricity Demand Forecast Comparison Report (Comparison Report)*, California Energy Commission Staff Report, CEC-400-2005-037, June 2005.

[112] The specific utilities included in each planning area is shown in Table 1-1 of the *Staff Draft Forecast*, with additional information on the aggregation included at the start of the chapter on each IOU's planning area.

The comparison report identified and explained differences between forecasts to provide a basis for Energy Commission decisions on what forecast or range of forecasts to adopt in the 2005 Energy Report proceeding.[113] The sections below on the individual planning areas explain the key differences between staff's forecast and the LSE forecasts.

Some parties requested confidentiality for some of the demand forecast data submitted. While the Energy Commission has determined that the basic annual peak demand forecast should be public for all LSEs, that determination was appealed to Sacramento Superior Court on June 10, 2005 by SCE. To maintain confidentiality of the data until the legal process is complete, staff uses certain aggregation conventions in the comparison report. Sales data submitted by ESPs are aggregated with staff estimates of non-filing ESPs and publicly owned utilities. For SCE, SDG&E, and PG&E, peak data are reported only at the planning area level.[114]

Staff's draft forecast and the comparison of this forecast with the aggregated forecasts supplied by the LSEs were the subject of a hearing on June 30, 2005. Because the staff forecast was expected to be a key input from the *2005 Energy Report* feeding into the CPUC's 2006 long-term procurement proceeding, the Committee offered parties an opportunity for cross examination on the use of models in preparing the forecast, consistent with Section 1822 of the Public Utilities Code. No parties requested the opportunity for cross examination.

Following the hearing and review of written comments the Committee directed staff to prepare a revised forecast that would include high and low cases in addition to a base case. The details of these comments, the Committee's direction to staff, and the resulting revised forecast are described in the section below on the Committee direction and the revised staff forecast. Staff published the revised forecast in September 2005.[115] The original LSE forecasts did not fall within the range across the three cases of the

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[113] *Comparison Report*, p. 1.

[114] *Id.* at 1-2.

[115] *California Energy Demand 2006-2016 - Staff Energy Demand Forecast, Revised September 2005 (Revised Staff Forecast)*, California Energy Commission Staff Final Report, CEC-400-2005-034-SF-ED2, September, 2005.

revised forecast, as discussed in more detail below. The SDG&E and SCE forecasts are both higher than the high case in the revised forecast; the PG&E forecast is below the low case.

6.2. General Issues between Staff and LSE Forecasts

At the June 30 hearing participants identified several key uncertainties driving the differences between staff and utility forecasts, including trends in commercial and industrial energy use, residential demographic trends, and currency of data. In addition, staff and utility forecasts use different types of models. These differences and the Committee's direction for resolving them are reviewed below and discussed in more detail in the IOU-specific sections that follow.

6.2.1. Model Assumptions

The draft staff forecast and the LSE forecasts differed in a number of key economic, demographic, and energy intensity assumptions. The Committee determined that these assumptions were all reasonably defensible, and directed staff to develop a range of forecasts based on the different perspectives. Specific differences are discussed below and their application in the revised forecasts are cases are summarized.

Demographic projections are a key driver of residential demand. Staff used the Department of Finance population projections, PG&E used Economy.com, and SCE and SDG&E used Global Insight. Global Insight's population growth rate is lower than both the Economy.com forecast and the Department of Finance forecast (which are very close), but it projects faster growth in the number of households, calculated as population divided by persons per household (PPH). Nationally, PPH are projected to continue to decline as the population ages. On average, California's trend has been the opposite, with increasing persons per household.[116]

Three persons-per-household options were presented at the hearing. The Global Insight and Economy.com forecasts assume that California will reverse its historic trend and revert to the national average of declining PPH. Thus, the IOU forecasts assume declining persons per household and increasing numbers of households. Staff assumes

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[116] Gorin, June 30 TR at 30, 31, 90.

continued increasing persons per household.[117] Local groups like SANDAG project constant persons per household.[118]

Both staff and the IOUs use economic projections developed by outside forecast services. The county level economic projections of Economy.com allow staff forecasts to better account for different economic trends within the state. For example, recent history has shown that Southern California is growing faster than Northern California.[119] PG&E also used Economy.com, while SCE and SDG&E used Global Insight. The Global Insight personal income forecast is much higher than the forecast staff derived from Economy.com. PG&E believes that the staff's economic input assumptions are reasonable.[120] SCE and SDG&E prefer their own.[121]

To capture these different perspectives, the high case assumes higher personal income and constant PPH, and the low case uses declining PPH and the older, lower personal income.

In the commercial sector, staff forecasted decreasing electricity use per square foot, reflecting the effects of building and appliance standards and slowing growth in office equipment demand. Some participants thought this reversal of recent trends unlikely and expected use per square foot to continue to increase.[122] PG&E thought that decreasing use per square foot was reasonable, given that the large build-up of office equipment inventory seen in the late 1990s was no longer occurring and that appliance energy efficiency improvements are expected to continue.[123] Staff's base case uses the original assumptions, while the high case assumes constant use per square foot.

Staff's industrial forecast was higher than that of the IOUs, reflecting only a slow decline in energy intensity.[124] Staff developed a revised forecast in which the forecasted

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[117] *Id.* at 90.

[118] *Id.* at 19 and staff June 30 workshop presentation "Forecast Overview," slide 18.

[119] Gorin, June 30 TR 12-13.

[120] Aslin, TR at 50.

[121] Mureau, June 30 TR at 65, 75; and SDG&E July 28 comment letter.

[122] June 30 TR 20-23, Mureau June 30 TR at 78.

[123] Aslin June 30 TR at 54-55.

[124] Mureau TR at 71, 72 and SCE June 30 workshop presentation, slide 7.

energy intensity trend is more consistent with historic trends. The high case uses the draft forecast assumptions, while the base and low cases assume a faster decline use per unit of production.

6.2.2. Baseline Data Uncertainty

An increased percentage of consumption reported to the Energy Commission under the quarterly fuel and energy reporting (QFER) requirements is reported as "unclassified."[125] This can lead to a misallocation of a portion of demand among industrial and commercial customers. Ten percent of non-residential consumption, 18,000 GWh, is currently not assigned to an end-use type in the QFER reporting.[126] Staff has assigned this unclassified load to the industrial or commercial sectors in proportion to the classified load, which may not accurately reflect sectoral differences. This creates great calibration problems in getting the sector starting points right and ripples through the forecast because different sectors have different capacity factors and growth rates. For example, SCE identified this as a key difference between its forecast and staff's.[127] The revised forecasts use the historic sector data submitted by SCE for calibration, which reduces the problem for this forecast. However, the Energy Commission still needs more accurate detailed historic data from the IOUs for future forecasts and demand analysis.

6.2.3. Treatment of Energy Efficiency and Demand Response

The staff draft forecast and the various LSE demand forecasts and resource plans used different conventions for treating energy efficiency and demand response programs. The forms and instructions for both the demand forecasts and resource plans specified that LSEs should include the effects of energy efficiency and demand response programs that had been approved in the demand forecast, while targets based on future programs that had not yet been funded should be included on the resource side.[128] The

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[125] *Staff Revised Forecast*, pp. 2-16.

[126] Gorin, June 30 TR at 21.

[127] June 30 TR at 63 - 65.

[128] *General Instructions for Demand Forecast Submittals*, California Energy Commission, November 3, 2004, p. 5; Forms and Instructions for the Electricity Resources and Bulk Transmission Data Submittal, California Energy Commission, CEC-100-2005-002-CF, January 2005, p.7.

staff draft demand forecast followed this convention, but the IOU forecasts did not. SDG&E's demand forecast incorporated future efficiency programs throughout the forecast period. PG&E's forecast includes the effects of historic levels of public good charge (PGC) funding. SCE's forecast did not include post-2008 effects, but it also did not include effects of some 2006-2008 programs. However, those effects were documented in its submittal as uncommitted. At the June workshop, SCE presented a forecast which included both 2006-2008 effects and post-2008 effects.

The staff forecast incorporates the effects of planned energy efficiency programs through 2008 and adopted building and appliance standards. Estimated savings by program are obtained directly from utilities and public agencies. All building and appliance standards are modeled within the sector forecast models. The impacts from many demand-side management (DSM) programs are estimated directly within the market sector end-use models. Use of the basic forecasting models to quantify standards and program savings depends on determining a certain set of characteristics for each program that describe how it will function including customer type affected, program measures end-use classifications, and compliance levels if the program is nominally mandatory. Energy impacts from some programs are quantified outside the sector models. Adjustments are made to distinguish between program-induced and non-programmatic, or market, effects. The final results are aggregated by sector and planning area and provided to the summary model where they are used to evaluate the appropriate sector forecasts. At the aggregate, the utility and program estimates are used to gauge the impacts included within the end-use models.

6.2.4. Model Differences

Staff uses end-use forecasting models for the residential, commercial and industrial sectors; econometric models for the agricultural and water pumping sectors; and trend analysis for the remaining small sectors.[129] PG&E, SCE and SDG&E use econometric models, which designed for and are better at near-term forecasting. SCE's

[129] Gorin, June 30 TR at 9.

biggest concern about staff's end-use models is the number of assumptions that have to be made.[130]

One evaluation problem that arises from use of different models is that it is difficult to compare input assumptions. Different models affect which input assumptions are the most critical, especially whether the residential sector driver is population or number of households. Parties acknowledged this difficulty and made some attempts at the hearing to comment on the drivers used by staff.

While all parties agree that the econometric models provide better near-term forecasts, the Energy Commission has determined that staff's end-use forecasting models provide a more appropriate basis for the forecasts needed for the long-term procurement proceeding.

6.3. PG&E Forecast

As shown in Table 6, the staff draft forecast and the aggregated LSE forecasts for PG&E's planning area[131] are very close, the peak within 0.5 percent in 2010 and 2 percent in 2016 and the energy within 1.2 percent in 2010 and 4 percent in 2016. Staff's draft forecast is higher than PG&E's except for peak demand for the years to 2010. Over the 2003-2016 planning horizon, growth rates are consistently within 0.2 percent, even though the forecasts are based on differing modeling techniques.[132] PG&E doesn't see any real difference between its and staff's planning area forecasts.[133] PG&E believes that the staff's economic input assumptions are reasonable.[134] Staff uses an end-use forecast, PG&E uses an econometric model.[135] No party expressed concerns about using two different forecasting methods, though IOUs generally felt econometric forecasting was more accurate in the short term.

[130] Mureau, June 30 TR at 76.

[131] In each of the three areas, the IOU serves roughly 80 to 90 percent of the total load. Therefore, in discussing the aggregated LSE forecasts for the different planning areas, we will typically refer to them as the IOU's forecast.

[132] Gorin, TR at 40 and slides 29, 30.

[133] Aslin, TR at 45.

[134] *Id.* at 50, 53.

[135] Gorin, 6/30 TR at 42.

Table 6: Comparison of Staff Draft Forecast with the Aggregated LSE Forecasts for PG&E Planning Area

	Consumption (GWH)				Peak (MW)		
	Aggregated Forecasts	Staff Draft Forecast	Percent Difference		Aggregated Forecasts	Staff Draft Forecast	Percent Difference
2000	96,844	96,822	-0.02%		20,698	20,698	0.00%
2003	94,114	95,638	1.62%		20,464	20,464	0.00%
2008	102,677	103,180	0.49%		22,537	22,331	-0.91%
2010	104,812	106,074	1.20%		23,069	22,975	-0.41%
2013	108,015	110,769	2.55%		23,909	24,040	0.55%
2016	110,401	114,614	3.82%		24,538	24,964	1.74%
Annual Average Growth Rates							
2000-2003	-0.95%	-0.41%			-0.38%	-0.38%	
2003-2008	1.76%	1.53%			1.95%	1.76%	
2003-2013	1.39%	1.48%			1.57%	1.62%	
2003-2016	1.61%	1.83%			1.83%	2.01%	
Historic values are shaded							

Source: *Electricity Demand Forecast Comparison Report (Comparison Report)*, California Energy Commission Staff Report, CEC-400-2005-037, June 2005.

Two PG&E-specific issues were raised at the June 30 hearing: treatment of post-2008 energy efficiency and calibration of the energy forecast. No additional issues were raised in written comments.

The post-2008 energy efficiency issue is a resource accounting issue.[136] Staff used the PG&E method in the 2003 Energy Report proceeding, but changed now that the CPUC's energy efficiency proceeding separated the targets into a committed 2006-2008 portion and an uncommitted post-2008 portion, which will be revisited later.[137]

As discussed above, the Energy Commission believes it is more prudent to treat post-2008 energy efficiency as a resource option rather than subtracting it from the load forecast. This approach acknowledges that post-2008 targets are subject to future energy agency regulation. Post-2008 energy efficiency will be the top of the loading order in the

[136] Aslin, 6/30 TR at 46.

[137] Marshall, 6/30 TR at 49.

supply/demand balance assessments. The Committee directed staff to use this approach in preparing the revised forecasts.

Also as discussed above, the calibration problem primarily results from reporting of unclassified electricity consumption in the Energy Commission's QFER data collection system. On the calibration issue, Aslin reported at the June 29 hearing that "staff and PG&E have worked out a common understanding of peak use in the historic year of 2003 (used to calibrate growth rates), but still have some work to do on the energy side. This is very important, because both projections should start from the same 'reality'."[138] Staff agreed that this was necessary.

The Committee directed staff to reach agreement with PG&E on historic calibration, which staff did in the revised forecast by using the consumption data provided by PG&E. While this issue was resolved for the current forecast cycle, additional work will be required to ensure that the problem is appropriately addressed in future cycles.

6.4. SCE Forecast

Table 7 shows the staff draft forecast and the aggregated LSE forecasts for SCE's planning area. SCE's forecast is less than 2 percent higher for both energy and peak through 2010. The difference in the forecasts increases after 2010, to 9.5 percent for energy and 6 percent for peak by 2016.[139] At the hearing, SCE presented a revised forecast that included post-2008 energy efficiency programs from its February submittal.[140] While this had the effect of narrowing the difference between the original SCE forecast (which is included in the aggregated forecast shown in Table 7) and the staff draft forecast, it is not consistent with the approach staff used in the draft forecast. SCE's forecast is higher due to its higher economic forecast, a different distribution of retail sales between a more robust commercial sector and a flatter industrial sector, and definitions and methodologies.[141]

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[138] Aslin, 6/29 TR at 52.

[139] Marshall, June 30 TR at 60, staff June 30 workshop presentation "SCE Planning Area Forecast", slide 31.

[140] Mureau, June 30 TR at 65.

[141] SCE slide 2, Mureau June 30 TR at 67.

Table 7: Comparison of Staff Draft Forecast with the Aggregated LSE Forecasts for the SCE Planning Area

	Consumption (GWH)				Peak (MW)		
	Aggregated Forecasts	Draft Staff Forecast	% Difference		Aggregated Forecasts	Draft Staff Forecast	% Difference
1990	n/a	78,271			n/a	17,564	
2000	92,469	92,543	0.08%		20,369	19,465	-4.44%
2003	89,534	90,045	0.57%		20,261	19,907	-1.75%
2008	98,837	98,088	-0.76%		22,543	22,468	-0.33%
2010	102,689	100,821	-1.82%		23,419	23,156	-1.12%
2013	110,800	104,670	-5.53%		25,064	24,108	-3.82%
2016	119,984	108,500	-9.57%		26,786	25,066	-6.42%
Annual Average Growth Rates							
1990-2000	n/a	1.69%			n/a	1.03%	
2000-2003	-1.07%	-0.91%			-0.18%	0.75%	
2003-2008	2.00%	1.73%			2.16%	2.45%	
2003-2013	1.65%	1.16%			1.65%	1.48%	
2003-2016	2.28%	1.44%			2.17%	1.79%	
Historic values are shaded							

Source: *Electricity Demand Forecast Comparison Report (Comparison Report),* California Energy Commission Staff Report, CEC-400-2005-037, June 2005.

SCE uses an econometric method, starting with Global Insight county-level economic data and adjusting the data as necessary.[142] SCE's forecast is primarily developed for procurement, so it focuses on getting the latest, most accurate near-term data for two to five years out.[143] SCE attributes its higher forecast to more robust economic growth, higher wages, and higher employment in the southland than does the economic forecast used by staff.[144]

SCE notes a large difference in the historical period between the SCE and Energy Commission count of households. The difference disappears by 2016, when the forecast

142 Mureau, June 30 TR at 65.

143 *Id.* at 75.

144 SCE June 30 workshop presentation, slide 5 and June 30 TR at 69.

is identical.[145] SCE forecasts fewer persons per household, leading to growth in total households, and forecasts growth in use per household.[146]

SCE's commercial forecast is higher than staff's due to higher short-term floorspace additions and continuing increases in use per square foot.[147] SCE hadn't reviewed staff's data on the impact of standards on commercial use per square foot but expressed concerns about it.[148] SCE has a flat industrial sector compared with staff's growing one. It believes that California manufacturers can't compete with offshore companies.[149]

SCE agrees with staff that its load factor will be declining due to a change in sector mix.[150] SCE and staff start at different historic load factors, which is important because SCE uses load factor as an input.

In total, the 2016 difference between staff's forecast and the forecast SCE presented at the hearing (as opposed to its February submittal that is included in the aggregated forecast in Table 7) is approximately 3 percent in peak, or equivalent to a one to two degree difference in temperature on the peak day.[151] However, SCE's inclusion of post-2008 energy efficiency reductions masked part of the difference in forecasts. When compared using common energy efficiency assumptions, the difference is 9.5 percent for energy and 6 percent for peak by 2016.[152]

At the hearing, no parties questioned SCE or staff, apart from the questions asked by the Committee. No party filed post-hearing comments on the demand forecast for SCE. As noted above, the Committee directed staff to use different economic and demographic assumptions in order to develop the low, base, and high cases in the

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[145] SCE June 30 workshop presentation, slide 4.

[146] *Id.* at slide 34, Mureau June 30 TR at 61-62.

[147] Staff June 30 workshop presentation "SCE Planning Area Forecast", slide 42, TR at 63, 64.

[148] Mureau, June 30 TR at 78.

[149] *id.* at 71, 72 and SCE June 30 workshop presentation, slide 7.

[150] Mureau, June 30 TR at 73.

[151] *ibid.*

[152] Marshall, June 30 TR at 60, CEC SCE slide 30.

revised forecast and to include only funded energy efficiency programs (through 2008) in the revised forecast.

6.5. SDG&E Forecast

As shown in Table 8, the aggregated LSE forecast for SDG&E's planning area is higher than the staff draft forecast. For the energy forecast, the SDG&E forecast is 1 percent higher by 2008 and almost 4 percent higher by 2016. In terms of the peak forecast, the differences are more than 2.5 percent in 2008 and more than 5 percent in 2016.[153] SDG&E assumes faster growth in the number of households and faster income growth. At the hearing, SDG&E pointed out that the differences between forecasts of approximately three years growth at the end of the forecast period understate the true differences since staff does not include post-2008 energy efficiency and SDG&E does. SDG&E's economic assumptions are similar to SCE's, so they have very similar issues with staff's forecast. The difference between forecasts is as much as eight years growth at the end.[154] Staff concurs that when the forecasts are compared using common energy efficiency assumptions, the forecasts are 12 percent different in 2016.

[153] Staff June 30 workshop presentation "SDG&E Planning Area Forecast", slide 30, June 30 TR at 88.

[154] Stephen Jack, June 30 TR at 91-92.

Table 8: Comparison of Staff Draft Forecast with the Aggregated LSE Forecasts for the SDG&E Planning Area

	Consumption (GWH)				Peak (MW)		
	Aggregated Forecasts*	Draft Staff Forecast	% Difference		Aggregated Forecasts*	Draft Staff Forecast	% Difference
1990	n/a	14,460			n/a	2,961	
2000	18,424	18,928	2.74%		3,485	3,472	-0.37%
2003	18,385	18,398	0.07%		3,902	3,921	0.48%
2008	20,626	20,405	-1.07%		4,468	4,350	-2.64%
2010	21,406	21,042	-1.70%		4,639	4,486	-3.30%
2013	22,575	21,981	-2.63%		4,889	4,686	-4.15%
2016	23,840	22,893	-3.97%		5,148	4,879	-5.22%
Annual Average Growth Rates							
1990-2000	n/a	2.73%			n/a	1.60%	
2000-2003	-0.07%	-0.94%			3.84%	4.14%	
2003-2008	2.33%	2.09%			2.75%	2.10%	
2003-2016	2.02%	1.70%			2.15%	1.70%	

Historic values are shaded

*- The SDG&E forecast included energy efficiency programs throughout the forecast period, so the values after 2008 are lower than they would be if the draft staff forecast method of only including the 2006-2008 energy efficiency programs had been used.

Source: *Electricity Demand Forecast Comparison Report (Comparison Report)*, California Energy Commission Staff Report, CEC-400-2005-037, June 2005.

Two-thirds of the difference between staff and SDG&E is in residential demand. SDG&E assumes faster growth in the number of households, implying declining persons per household and faster income growth, because Global Insight has a higher economic forecast than Economy.com. For SDG&E, the key difference is in the number of households, not use per household.[155]

The difference in population and PPH is attributable to different sources. SDG&E believes that the data from the Department of Finance (DOF) and Economy.com used by staff is the low end of the plausible range, while their sources are towards the higher end. Their forecast is consistent with what the University of California at Los Angeles recent forecast and with the forthcoming SANDAG forecast.[156]

[155] Jack, June 30 TR at 93.

[156] *Id.* at 92.

SDG&E did not have an opinion about commercial use per square foot floor space trends.[157]

Staff and SDG&E also had a starting point problem. The staff's draft forecast for 2006 was nearly the same as SDG&E's 2005 starting point. The staff was a year's growth off on its starting point. Staff's last historic year was 2003. If they had used 2004 actual data, much of the 1.5 percent calibration problem might disappear.[158] This view was reiterated in the July 22 follow-up comments that said the Energy Commission needs to adjust the peak starting point to account for normal weather and revise its short-term outlook.

SDG&E stated that staff's weather-sensitive residential load is understated by more than 50 percent. This is significant because it is a fast-growing segment of load. The adjustment could add one year of growth to the peak forecast. SDG&E stated that it has load study information that supports its view.[159] SDG&E also recommended that staff continue to make progress on adding more weather stations, including considerations of humidity and minimum temperatures.[160]

The Committee directed staff to resolve these issues with SDG&E. The revised forecast has adjusted its base peak forecast upwards to account for a return to normal weather. The adjustment of peak to account for normal weather lowers the load factor slightly. This served to increase the peak estimates for all forecast years. The revised forecast also uses revised sector load shapes that increase weather-sensitive load and decrease base load for the SDG&E region. The revised forecast did not reflect other model changes suggested by SDG&E because it has not yet provided adequate documentation to assess the viability of the model results and claims laid out in their comments. Staff is directed to work with SDG&E to jointly improve weather-sensitive modeling.

No parties had questions for SDG&E or staff on their forecasts. SDG&E filed a follow-up comment letter on July 28 that addressed the issues discussed above.

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[157] *Id.* at 99.

[158] *Id.* at 94-95.

[159] *Id.* at 96-98.

[160] *Id.* at 99 and SDG&E July 22 comment.

6.6. Committee Direction and Revised Staff Forecast

The fundamental issue facing the Energy Commission is developing a plausible range of energy and peak demand that IOUs may face in the next decade for their bundled service customers. This can be broken down into specific estimates of general economic and demographic trends; energy intensity trends in each of the sectors; accuracy of historic end-use and trend data; potential impacts of regulatory decisions on departing load; and means of addressing the uncertainty inherent in all these factors.

The Committee had a clear and complete record on energy forecasts and parties agreed on the source of differences. Small differences compound over time, so that they could translate into several years' growth when compared using common assumptions. The Committee chose not to adopt a forecast presented at the hearings, but directed staff to produce a revised forecast using Committee-directed assumptions reflecting positions presented in testimony and hearings.

In response to the testimony and hearings, the Committee directed staff to revise some of the historic data used for the forecast. Some utilities pointed out that some of the historical data used by staff was inconsistent with their own data. In these cases staff replaced historical consumption and peak data with the values reported on the demand forms submitted to the Energy Commission by each LSE. The draft forecast also used 2003 consumption as the last historical year. This contributed to starting point differences between the staff and utility forecasts using more recent data. To address these concerns, all the revised forecasts incorporate 2004 electricity and natural gas consumption, peak demand, and weather data.

The base case forecast also uses a new higher forecast of per capita income produced by Economy.com in June 2005, with updated population estimates. Since the June 2005 forecast the Department of Finance reestimated interim population and PPH size by county for January 2001 through 2005.[161] These revised estimates were factored into the new base case population and PPH forecasts.

The Committee directed staff to vary key economic and demographic assumptions to develop a reasonable range of possible outcomes. Table 9 summarizes

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[161] State of California, Department of Finance, E-5 City/County Population and Housing Estimates , Revised 2001-2004,with 2000 DRU Benchmark. May 2005.

the changes from the draft staff forecast to the base, low, and high cases in the revised staff forecast. The residential high case incorporates assumptions similar to that of the IOU forecasts, using the new, higher real personal income and assuming constant PPH through the forecast period, resulting in more households. The low forecast uses the new PPH forecast with the older per capita income projection.

Table 9: Composition of Revised Forecasts

	Industrial	Mining	Commercial	Residential
Base	Decreased kwh per output	Increased kwh per output	No 2005 lighting standards, no 98 office lighting standards; no misc./office equipment growth	New income, New persons per household
Low	Decreased kwh per output	Increased kwh per output	No 2005 lighting standards; no misc./office equipment growth	June income, New persons per household
High	Jun-05 Forecast	Increased kwh per output	No lighting standards effects; higher misc. (2%). and office equipment growth (1%)	New income, Constant persons per household

For the commercial sector, the Committee directed staff to develop a high case with increasing-to-flat use per square foot. To accomplish this, impacts of the new 2005 nonresidential lighting standards were removed from the model, and growth of demand in the miscellaneous and office equipment end uses was accelerated by 1 to 2 percent per year. For the low case, growth of office and miscellaneous equipment was set at zero, and some lighting standards effects not included in the base case were added back in.

In response to comments that the industrial forecast seemed unreasonably high given marketplace conditions in California, the Committee directed staff to develop a revised industrial forecast for the low case. Staff reviewed the historical use per output for each industry group. Staff evaluated the trends in energy use per output for each industrial group and revised the energy intensity growth rates to produce a forecast more consistent with historical trends. For manufacturing industries, this entailed a faster decline in use per dollar of value of shipments over the forecast period. This higher forecast is used for the low and base case forecast, while the original staff forecast, calibrated to 2004 data, is used in the high case. The oil and gas extraction industry, however, has become more electricity intensive in recent years. In the revised mining sector forecast, used for all cases, this trend is projected to continue.

As discussed above, the effects of energy efficiency programs through 2008, which have had their funding approved, are incorporated into the demand forecast, while post-2008 programs are listed on the resource side.

Also as discussed above, the Energy Commission has determined that departing load uncertainty is a resource uncertainty that is best addressed through appropriate exit fees and coming-and-going rules. We will not insert a level of departing load into the forecasts. The revised forecasts assume direct load growth at half the sector growth rate of the planning area forecast.

The revised staff forecast, based on the Committee's direction, was published on September 27, 2005.[162] Table 10 summarizes statewide annual energy and capacity and compares these three cases to the draft staff forecast. Tables 11 through 13 summarize the low, medium and high forecasts for the three planning areas. Comparisons between the revised staff energy forecasts and the IOU-submitted forecasts are discussed in the next section.

[162] *Revised Staff Forecast*.

Table 10: Statewide Electricity Demand: Comparison of Draft and Revised Staff Forecasts

Consumption (GWH)

	Draft Staff Forecast	Revised Staff Forecast			Percent Difference Base/ Staff Draft	Percent Difference High/ Low
		Low	Base	High		
1990	229,367	229,375	229,375	229,375	0.00%	0.00%
2000	262,985	265,021	265,021	265,021	0.77%	0.00%
2004	272,386	270,927	270,927	270,927	-0.54%	0.00%
2008	285,867	285,317	286,813	289,002	0.33%	1.29%
2013	304,355	302,059	304,400	310,869	0.01%	2.92%
2016	314,471	310,716	313,397	323,372	-0.34%	4.07%
Annual Average Growth Rates						
1990-2000	1.38%	1.45%	1.45%	1.45%		
2000-2004	0.88%	0.55%	0.55%	0.55%		
2004-2008	1.21%	1.30%	1.43%	1.63%		
2004-2016	1.20%	1.15%	1.22%	1.49%		

Peak (MW)

	Draft Staff Forecast	Revised Staff Forecast			Percent Difference Base/ Staff Draft	Percent Difference High/ Low
		Low	Base	High		
1990	46,907	47,431	47,431	47,431	1.12%	0.00%
2000	53,758	54,028	54,028	54,028	0.50%	0.00%
2004	56,339	56,435	56,435	56,435	0.17%	0.00%
2008	60,878	60,640	61,042	61,528	0.27%	1.46%
2013	65,144	64,515	65,144	66,525	0.00%	3.11%
2016	67,569	66,656	67,379	69,473	-0.28%	4.23%
Annual Average Growth Rates						
1990-2000	1.37%	1.31%	1.31%	1.31%		
2000-2004	1.18%	1.10%	1.10%	1.10%		
2004-2008	1.96%	1.81%	1.98%	2.18%		
2004-2016	1.53%	1.40%	1.49%	1.75%		

Historic values are shaded

Source: *California Energy Demand 2006-2016 - Staff Energy Demand Forecast, Revised September 2005 (Revised Staff Forecast)*, California Energy Commission Staff Final Report, CEC-400-2005-034-SF-ED2, September, 2005.

Table 11: PG&E Planning Area Electricity Demand: Comparison of Draft and Revised Staff Forecasts

Consumption (GWH)

	Low	Base	High	Percent Difference High/Low
1990	86,806	86,806	86,806	0.00%
2000	101,528	101,528	101,528	0.00%
2004	101,147	101,147	101,147	0.00%
2008	107,025	107,366	108,574	1.45%
2016	117,870	118,390	123,636	4.89%
Annual Average Growth Rates				
1990-2000	1.58%	1.58%	1.58%	
2000-2004	-0.09%	-0.09%	-0.09%	
2004-2008	1.42%	1.50%	1.79%	
2004-2016	1.28%	1.32%	1.69%	

Peak (MW)

	Low	Base	High	Percent Difference High/Low
1990	17,039	17,039	17,039	0.00%
2000	20,698	20,698	20,698	0.00%
2004	20,760	20,760	20,760	0.00%
2008	22,053	22,142	22,406	1.60%
2016	24,466	24,600	25,694	5.02%
Annual Average Growth Rates				
1990-2000	1.96%	1.96%	1.96%	
2000-2004	0.07%	0.07%	0.07%	
2004-2008	1.52%	1.62%	1.93%	
2004-2016	1.38%	1.42%	1.79%	

Historic values are shaded

Source: *California Energy Demand 2006-2016 - Staff Energy Demand Forecast, Revised September 2005 (Revised Staff Forecast)*, California Energy Commission Staff Final Report, CEC-400-2005-034-SF-ED2, September, 2005.

Table 12: SCE Planning Area Electricity Demand: Comparison of Draft and Revised Staff Forecasts

Consumption (GWH)

	Low	Base	High	Percent Difference High/Low
1990	81,579	81,579	81,579	0.00%
2000	98,346	98,346	98,346	0.00%
2004	97,389	97,389	97,389	0.00%
2008	102,909	103,437	104,089	1.15%
2016	112,577	113,409	116,597	3.57%
Annual Average Growth Rates				
1990-2000	1.89%	1.89%	1.89%	
2000-2004	-0.24%	-0.24%	-0.24%	
2004-2008	1.39%	1.52%	1.68%	
2004-2016	1.22%	1.28%	1.51%	

Peak (MW)

	Low	Base	High	Percent Difference High/Low
1990	17,564	17,564	17,564	0.00%
2000	19,465	19,465	19,465	0.00%
2004	20,546	20,546	20,546	0.00%
2008	22,328	22,483	22,624	1.33%
2016	24,688	24,934	25,573	3.59%
Annual Average Growth Rates				
1990-2000	1.03%	1.03%	1.03%	
2000-2004	1.36%	1.36%	1.36%	
2004-2008	2.10%	2.28%	2.44%	
2004-2016	1.54%	1.63%	1.84%	

Historic values are shaded

Source: *California Energy Demand 2006-2016 - Staff Energy Demand Forecast, Revised September 2005 (Revised Staff Forecast)*, California Energy Commission Staff Final Report, CEC-400-2005-034-SF-ED2, September, 2005.

Table 13: SDG&E Planning Area Electricity Demand: Comparison of Draft and Revised Staff Forecasts

Consumption (GWH)

	Low	Base	High	Percent Difference High/Low
1990	14,926	14,926	14,926	0.00%
2000	19,295	19,295	19,295	0.00%
2004	19,627	19,627	19,627	0.00%
2008	20,917	21,051	21,186	1.29%
2016	23,323	23,490	24,033	3.05%
Annual Average Growth Rates				
1990-2000	2.60%	2.60%	2.60%	
2000-2004	0.43%	0.43%	0.43%	
2004-2008	1.60%	1.77%	1.93%	
2004-2016	1.45%	1.51%	1.70%	

Peak (MW)

	Low	Base	High	Percent Difference High/Low
1990	2,961	2,961	2,961	0.00%
2000	3,472	3,472	3,472	0.00%
2004	4,071	4,071	4,071	0.00%
2008	4,422	4,451	4,481	1.33%
2016	4,933	4,970	5,088	3.14%
Annual Average Growth Rates				
1990-2000	1.60%	1.60%	1.60%	
2000-2004	4.06%	4.06%	4.06%	
2004-2008	2.09%	2.26%	2.43%	
2004-2016	1.61%	1.68%	1.88%	

Historic values are shaded

Source: *California Energy Demand 2006-2016 - Staff Energy Demand Forecast, Revised September 2005 (Revised Staff Forecast)*, California Energy Commission Staff Final Report, CEC-400-2005-034-SF-ED2, September, 2005.

6.6.1. Comparison of Staff Revised Forecast to IOU Forecasts

As mentioned previously, the forecasts provided by the IOUs for electricity sales fall outside the range of the revised staff forecast, with the PG&E forecast lower than the low case in revised staff forecast and the SCE and SDG&E forecasts higher than the high case.[163] These differences are discussed below.

The Energy Commission is adopting the revised staff forecasts, since staff's end-use modeling methods are more appropriate for long-term planning purposes.

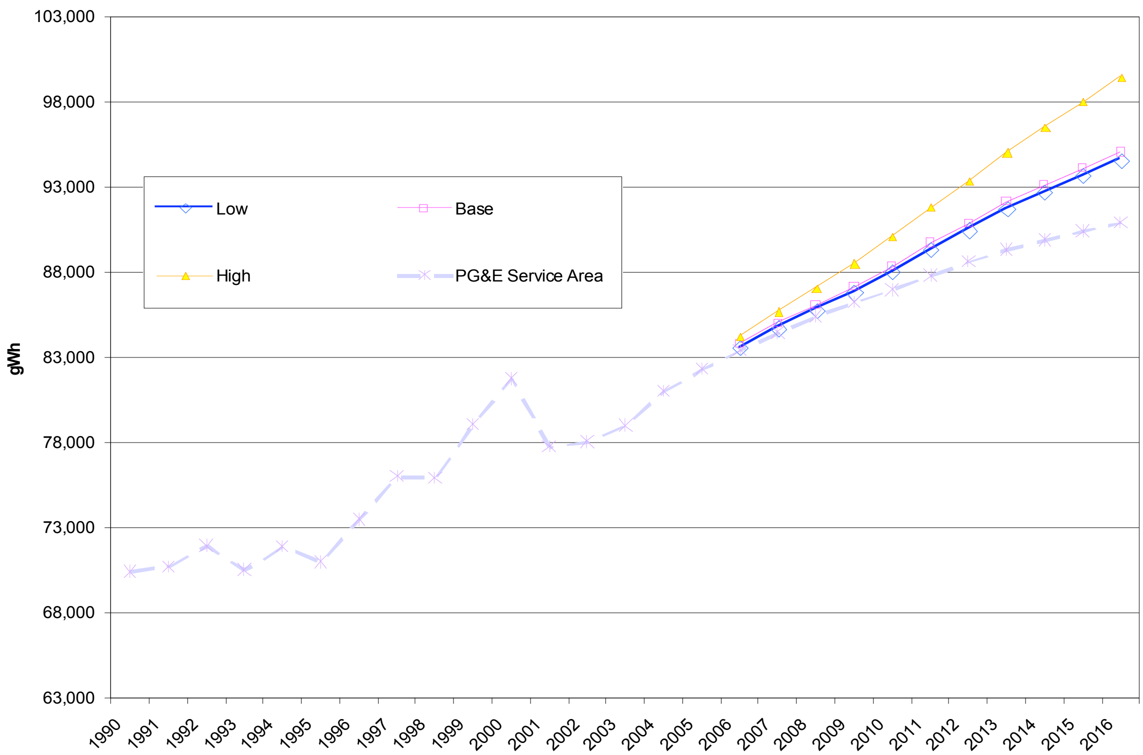
6.6.1.1. PG&E

While the revised staff forecast and PG&E forecast are very similar in the early years, PG&E's forecast is 3 percent lower than staff's low case by 2014. The key differences are with conservation assumptions. First, because of the econometric methods used by PG&E, it considers the effects of historic levels of energy efficiency program funding, incorporated in its forecast beyond 2008. In addition, PG&E assumes persistence of behavioral conservation from the energy crisis, while staff does not. Therefore the staff forecast projects increasing residential use per household, while PG&E projects flat to decreasing use per household.[164]

[163] No direct comparison can be made between the annual bundled-customer peak in the IOU-supplied forecasts and the revised staff forecasts. The IOU annual peak numbers are being treated as confidential while the court case filed by SCE seeking to overturn the Energy Commission's determination that this data was not confidential is pending.

[164] *Comparison Report*, Figure 2-5.

Figure 1: PG&E Service Area Electricity Sales Forecasts



6.6.1.2. SCE

The forecast submitted by SCE is 5 percent higher than staff's high case in 2013. However, this forecast did not include effects of some programs to be funded in 2006-2008 that SCE treated as uncommitted at the time it submitted its forecast. Using SCE data submitted on the DSM forms, staff estimated an adjusted forecast that includes these effects. This adjusted forecast is lower than the staff low forecast initially, but one percent higher than the high by the end of the forecast period. As in the June forecast comparison, assumptions about trends in commercial sector energy use drive the differences. In the staff's high forecast, accelerated office equipment growth and the reduced effects from building and appliance standards produce constant commercial electricity use per square foot (as opposed to declining use in the base case), while the SCE forecast assumes increasing use per square foot.[165]

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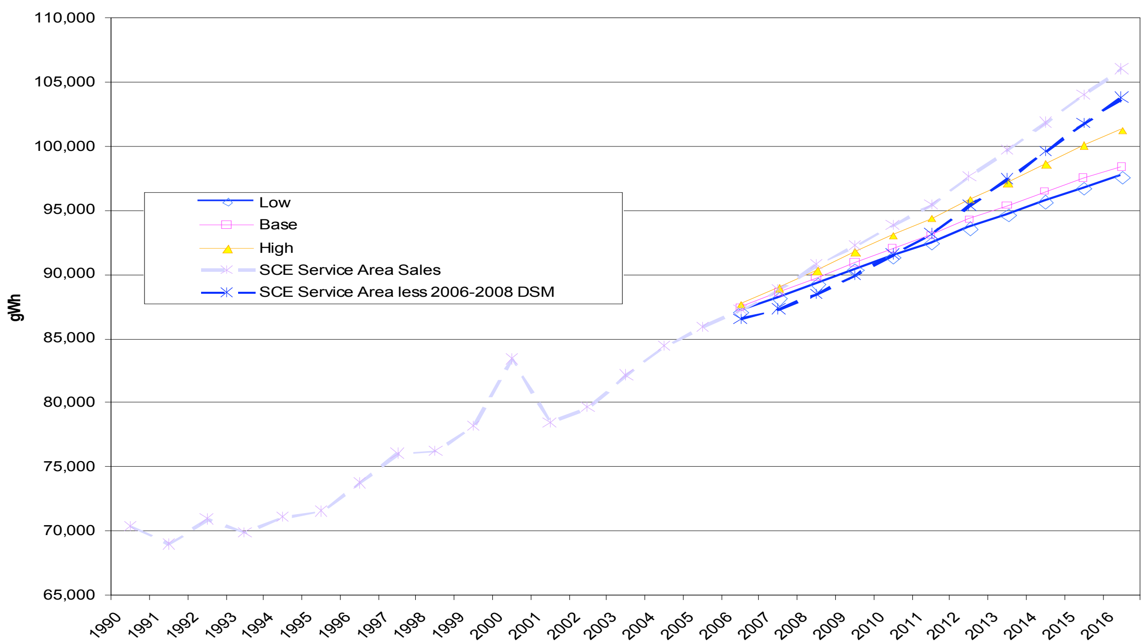
[165] *Comparison Report*, Figure 3-12.

While use per square foot has been increasing in recent years, this trend has reflected the rapid penetration of computers and related equipment. Staff's perspective is that the future rate of new penetration is likely to slow and will be offset as older electronic equipment is replaced with more energy efficient models.

Figure 2: SCE Service Area Electricity Sales Forecasts



6.6.1.3. SDG&E

SDG&E submitted a forecast including the effects of energy efficiency programs from 2008 through 2016, which for this proceeding are considered uncommitted. This forecast is very similar to staff's high forecast, within 0.5 percent until the last two forecast years.

However, adding the uncommitted effects back to the forecast produces a "no uncommitted" forecast that is 5 percent higher than staff's high case by 2013, and almost 10 percent higher by 2016. SDG&E 's documentation does not describe in detail how conservation and standards are accounted for, but some of the difference between the staff high case and the SDG&E "no uncommitted" forecast may reflect differences in how energy efficiency impacts are accounted for. Savings that SDG&E attributes to future DSM programs may to some extent be already accounted for in the Energy

Commission models as part of the effects of building decay, equipment replacement, price effects, and building and appliance standards.

However, this cannot explain all the difference; staff's high case has removed many of the effects of commercial building standards, and SDG&E's own econometric forecast methods would also tend to incorporate the effects of historic levels of program activity into the forecast. The growth of use per capita in SDG&E's "no uncommitted" forecast, shown in Figure 4, is comparable to the rapid growth during the technology boom of the late 1990s. While we have seen similar increases in 2003 and 2004, these likely reflect the rebound from the energy crisis and the effects of the recent construction boom. While more such cyclical phenomena (either positive or negative) may occur in the future, such trends are generally short lived and not sustained over the period indicated in the SDG&E "no uncommitted" forecast.

Figure 3: SDG&E Service Area Electricity Sales Forecasts

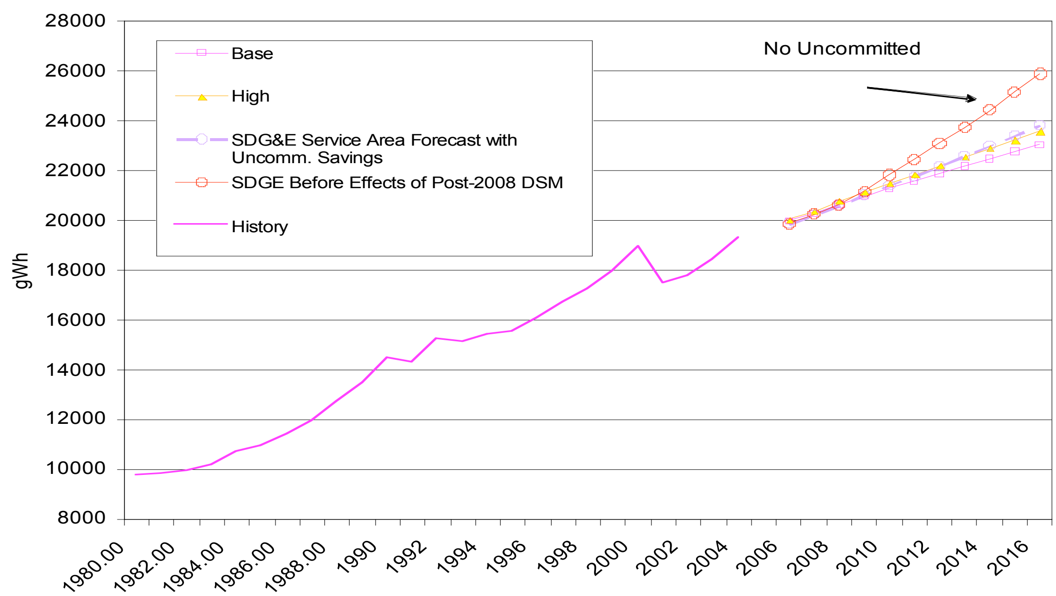
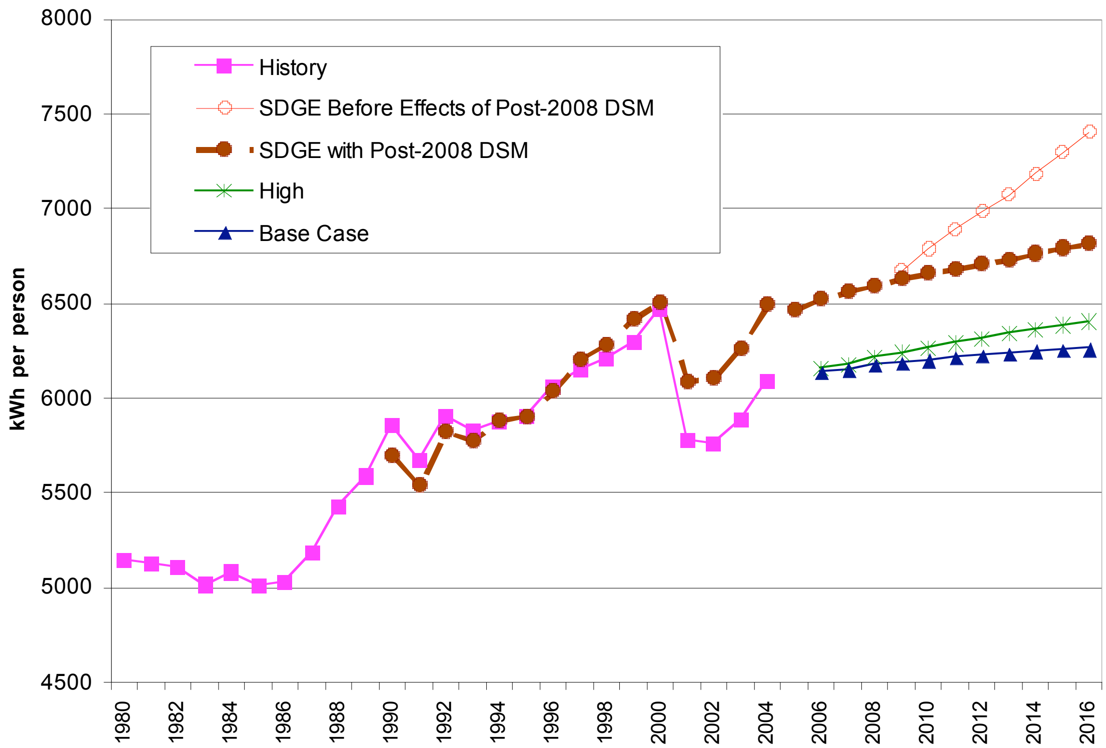


Figure 4: SDG&E Service Area Electricity Consumption per Capita



7. Resource Plans and Range of Need

For each of the three IOUs, the following sections summarize staff's review of key elements of the resource plans and supporting information filed by the IOUs, and then present the range of need.

7.1. PG&E Resource Plan and Range of Need

7.1.1. Preferred Resources

7.1.1.1. Energy Efficiency

PG&E's resource plans include an energy efficiency program that it asserts will meet CPUC targets in D.04-09-060. PG&E stated that its portfolios were constructed in a bottoms-up manner consistent with the *Energy Action Plan* loading order, with energy efficiency targets included first. The energy efficiency programs have an aggressive ramp-up, a focus on programs that meet peak power needs in the near term, and aggressive cost-effective energy savings starting in 2007.[166] PG&E also stated its commitment to achieving its long-term targets and is actively developing programs to achieve this level of energy efficiency."[167]

While PG&E appears to be committed to achieving considerable peak savings, its novel program strategy in the 2006-2008 period will bear close watching to confirm that it can deliver the savings it anticipates. PG&E is to be commended for trying a completely redesigned customer-oriented and market-based approach for achieving energy efficiency.

The Energy Commission is including the uncommitted portion of the current CPUC-adopted energy efficiency targets within the preferred resource category in the range of need tables.

7.1.1.2. Demand Response

PG&E used its 5 percent targets to set the same demand response forecast in all its resource plan scenarios. Since the demand response programs serve all system level load customers, the projections did not vary with differing assumptions about

[166] *RPSA Report*, p. 23, 24.

[167] PG&E, July 22 Comments. p. 2.

departing load.[168] Staff agrees that PG&E's description of its plan is reasonable, but notes that SCE and SDG&E chose to also provide an alternative forecast to illustrate their own internal estimates of available demand response. PG&E did not provide such an estimate.

The Energy Commission is showing the current CPUC target of 5 percent of service territory load in 2007 and beyond as the amount of preferred demand response resources in the need tables. The Energy Commission recognizes that the CPUC may decide to revise those targets in its demand response proceeding and expects that the values in the need tables will be appropriately adjusted if new targets are adopted.

7.1.1.3. Renewables

All PG&E's resource portfolios include a minimum of 20 percent renewable energy by 2010.[169] The company built a renewable portfolio in its preferred plan, which reaches 23 percent by 2013, and used that same case in the reference case, with its higher load, which reaches 20 percent by 2010 and retains that percentage through 2016. Its accelerated renewables case is built from its preferred case and reaches 28 percent by 2016.[170]

PG&E states that its proposed renewable resources are based on their likely availability and value to the system, though actual procurement of renewable generation will occur based on the least-cost best-fit analysis of bids received through its proposed RPS Procurement Plan and accompanying RFO for Renewable Resources. In describing its supply resource options, PG&E states that it relied primarily on renewable resource information published by the Energy Commission as part of its *2004 Energy Report Update.*[171]

Staff found the renewable development assumptions used in these plans to be plausible after comparing the plans by technology and location with the remaining

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[168] PG&E, July 22 Comments, p. 3.

[169] PG&E, April 1 filing, p. 4.

[170] *RPSA Report*, pp.52-53.

[171] *RPSA Report*, p. 52

technical potential in the Energy Commission's *2003 Renewable Resources Development Report*.[172]

While PG&E states that the amount of renewable resources located and available in the NP 15 transmission zone is sufficient to meet the 20 percent renewable procurement target, PG&E believes it will likely need to procure renewable resources from other areas to achieve a 33 percent target. This would require additional transmission and/or the use of renewable energy credits. PG&E believes it may be more efficient, environmentally beneficial, and less expensive to ratepayers to allow the use of renewable energy credits instead of building additional transmission.[173]

PG&E developed a resource portfolio to reach 33 percent by 2020 but states that:

> Based on information currently available this portfolio is theoretically possible, but PG&E is concerned that this portfolio will be extremely difficult to realize and the costs of achieving a 33 percent renewable portfolio are very likely to be substantially understated. PG&E believes the total cost of the Accelerated Renewable portfolio is much greater than the costs presented here reflect. PG&E assumed the resource potential and costs for renewable development are based on CEC-developed technical potential information. This cannot however, provide sufficiently detailed information regarding the type and location of the renewables that will ultimately constitute PG&E's portfolio, and as a result specific cost estimates have not been developed.[174]

For example, PG&E reported that, in addition to the generation costs reported in Attachment E, Table 2, "to achieve the 20 percent renewable resources level in all scenarios, it will incur approximately $170-$230 million in incremental transmission costs (other than interconnection) which will increase the transmission component of its rates."[175]

The Energy Commission has decided to use the generic renewable energy and capacity values developed by PG&E for the accelerated renewables case within the preferred renewables identified in the range of need table. The Energy Commission recognizes that this scenario was based on a different demand forecast, so the resulting

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[172] *RPSA Report*, p. 53

[173] *RPSA Report*, p. 56

[174] Energy Commission Integrated Energy Policy Report PG&E Electric Resource Supply & Transmission Plan, April 26, 2005, page 13.

[175] PG&E, April 26, p. 13.

trajectory of that level of future purchases would not be 33 percent of demand in 2020. Nonetheless, the primary purpose of identifying a preferred level of renewable resources on the need tables is to avoid procuring so much in non-preferred resources that renewable purchases to meet future targets are precluded. Therefore, the Energy Commission considers the generic renewable resources identified by PG&E in its accelerated renewables case, which all parties agreed would be technically achievable (though at uncertain costs), provide a useful benchmark. The Energy Commission invites comments on this approach and recommendations on alternative approaches for determining the amount of preferred renewables to identify in the need tables.

7.1.1.4. Distributed Generation

In its assessment of PG&E's resource plan filings, staff could not determine what assumptions PG&E used regarding future DG. Staff proposed that an extrapolation of 2002-2004 actual installations, 2.5 MW per year, should be used.[176] In its July 22, 2005, comments, PG&E clarified that it used the same data source and the same assumption of 2.5 MW per year that staff recommended.[177]

In the *Draft Energy Report*, the Energy Commission recommends that "by the end of 2006, the Energy Commission and CPUC should work collaboratively to translate this goal [of 5,400 MW of CHP statewide by 2020] into yearly procurement targets for IOUs."[178] Once these goals are established, the CPUC should incorporate them into the preferred resource category on the need tables.

7.1.2. Energy Resource Needs

The energy range of need for PG&E is shown in Appendix B Tables B-1, B-2, and B-3 for the base, low and high revised staff forecasts, respectively, and is described in the sections below.

7.1.2.1. Utility Controlled Resources

PG&E's resource plans included the annual energy for utility controlled nuclear, fossil, and hydroelectric resources. For nuclear resources, PG&E's plans assume

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[176] *RPSA Report*, pp. 66-67.

[177] PG&E July 22 Comments, pp. 3-4.

[178] *Draft Energy Report*, p. 67.

relatively flat levels of generation throughout the forecast period and a slow decline in generation from hydro resources, with the 2016 hydro generation at approximately 80 percent of the 2009 value. For fossil resources, PG&E did not include any generation in its reference case for 2009 and beyond, though it included 150 MW of capacity based on the planned replacement of the Humboldt Bay Power Plant. The other three resource plans filed by PG&E showed between 170 and 180 GWh of fossil generation between 2009 and 2016, which would correspond to a capacity factor of approximately 15 percent for 150 MW of capacity.[179] Overall, PG&E's reported utility-controlled resources total between 30,000 and 33,000 GWh for the years 2009 through 2016.

7.1.2.2. Contractual Resources

PG&E's resource plans show a significant drop in contractual resources throughout the forecast period, with the largest drop between 2009 and 2010 due to the decline of energy supply from DWR contracts from more than 21,000 GWh in 2009 to just more than 3,000 GWh in 2010. This total declines to about 1,000 GWh in 2012 and disappears in 2013.

PG&E projected that energy resources from QF contracts would remain relatively constant throughout the period, with the energy supply from these contracts between 19,000 and 20,000 GWh. Energy supplies from existing renewable contracts and other bilateral contracts decline throughout the planning period, from a combined total of slightly more than 4,000 GWh in 2009 to less than 500 GWh in 2016, presumably reflecting expiration of such contracts.

While the aggregated data tables counted short-term and spot market purchases as part of the total existing and planned resources, the Energy Commission has chosen to consider these purchases as part of the need to be filled by PG&E.

7.1.2.3. Energy Range of Need

The balance of energy demand versus existing and planned resources for PG&E show relatively modest energy needs across the three demand forecasts of 10 to 12 percent of the total energy requirement in 2009, to 45 to 50 percent by 2016. As discussed above, the Energy Commission is adding an increment to this balance to

[179] *Aggregated Tables Report*. The PG&E reference case public tables showed more than 3,500 GWh for fossil generation, which is not consistent with the 150 MW of reported capacity.

ensure that adequate procurement allows for the orderly replacement of the retiring aging power plants by 2012. PG&E's full energy share for aging plant replacement is approximately 7,500 GWh. The aging plant replacement increment is stepped up to this full amount over the period from 2009 through 2012.

The resulting total energy need for PG&E ranges from approximately 10,000 to 12,000 GWh in 2009 to 51,000 to 56,000 GWh in 2016. These values represent below 15 percent of the total energy requirement in 2009 and about 55 percent in 2016.

In addition to developing the total range of need, the Energy Commission is reporting on the amount of preferred resources that the utilities should plan to obtain ,consistent with the loading order. The Energy Commission recognizes that ongoing and future proceedings at the CPUC may result in adjustments to these numbers, but recommends that the authority the CPUC grants for open source procurement be adjusted to ensure that these preferred resources are not crowded out in the future.

The uncommitted energy efficiency savings included in the preferred resources are based on the estimates provided by PG&E based on the targets established by the CPUC in D.04-09-060, adjusted to account for the inclusion of committed energy efficiency programs through 2008 that are included in the revised demand forecast. These savings ramp up from approximately 1,000 GWh in 2009 to 9,000 GWh in 2016.

As discussed above, the Energy Commission is including in the preferred resources category renewable resources consistent with the accelerated goal of 33 percent renewables by 2020 that the Energy Commission recommended for PG&E in the *2004 Energy Report Update*. While the CPUC cannot under current law require RPS procurement beyond 20 percent, the Energy Commission places great weight on the rebuttable presumption for renewable resources in any RFO seeking generation resources established by the CPUC in D.04-12-048, despite PG&E's lack of specificity about how it intends to implement this policy directive.

As directed by the Energy Commission, PG&E filed an accelerated renewables resource plan scenario aiming at 33 percent renewable resources by 2020. While the trajectory in this resource plan is not based on the revised staff demand forecast, it is the most detailed information in the record on the possible path that PG&E could follow to meet the accelerated targets. Therefore, the Energy Commission is using the generic renewable energy needs identified by PG&E in this resource plan scenario as a placeholder to ensure that PG&E will be able to purchase adequate renewables to meet the enhanced goals should they be enacted into law. The Energy Commission invites comments on this approach and other recommendations on alternate approaches for determining the amount of preferred renewables to identify in the need tables.

These preferred resources represent more than half of the total energy needs identified for PG&E in 2009 in all three cases. With the expiration of many DWR contracts greatly increasing the total need in 2010, the portion of total need represented by the preferred resources drops to between 25 and 30 percent in the three cases in 2010, slowly increasing to 35 to 40 percent by 2016.

Though targets have not yet been established, the Energy Commission has recommended that the CPUC and Energy Commission establish targets for distributed generation and combined heat and power resources by the end of 2006. When these targets are established, these need tables should be updated to reflect the targets, resulting in an increase in the preferred resources and a reduction in the level of undesignated need.

7.1.3. Capacity Resource Needs

The capacity range of need for PG&E is shown in Appendix B Tables B-4, B-5, and B-6 for the base, low and high revised staff forecasts, respectively, and is described in the sections below.

7.1.3.1. Utility-Controlled Resources

PG&E's resource plans included public tables providing the annual capacity for utility-controlled nuclear, fossil, and hydroelectric resources for the years 2009 through 2016.[180] These tables show a nearly constant level of capacity available from these existing and planned resources, with the only change a 67 MW reduction in hydroelectric capacity starting in 2014. The Energy Commission includes these resources in its calculation of the range of need.

7.1.3.2. Contractual Resources

For contractual resources, the public capacity tables in PG&E's resource plans only included the DWR contracts. The aggregated PG&E planning area capacity tables also show totals for QF contracts (no QF contracts are held by other LSEs in PG&E's

[180] The public tables filed by PG&E were published in Appendix B of the *RPSA Report.*

planning area, so this total is also PG&E-specific), renewable contracts, and other bilateral contracts.[181]

The DWR contracts assigned to PG&E decline rapidly starting in 2009, with total capacity declining from 4,392 MW in 2009 to 263 MW in 2012. No DWR contracts remain in place after 2014. PG&E projected QF capacity to remain relatively constant throughout the period, with the 2009 QF capacity of 2,559 MW declining only to 2,472 MW in 2016. These IOU-specific contractual resources consistently represent more than 60 percent of the capacity of the contractual resources for each year in the capacity tables for PG&E's planning area.

The aggregated tables show declining capacity from existing renewable contracts and other bilateral contracts through the planning period, going from a combined total of 1,691 MW in 2009 to 896 MW in 2016. Due to confidentiality constraints, these values include contracts held by POUs in PG&E's service territory and a share of contracts held by ESPs. As discussed above, the Energy Commission intends in the final version of this report to subtract the POU data from these totals, resulting in a distribution service area estimate for the renewables contracts and other bilateral contracts.

While the aggregated data tables counted short-term and spot market purchases as part of the total existing and planned capacity, the Energy Commission has chosen to consider these purchases as part of the need to be filled by PG&E.

7.1.3.3. Capacity Range of Need

As described in more detail above, the need for each forecast was calculated by subtracting the identified resources and existing interruptibles capacity from the forecast demand and then adding sufficient capacity to account for PG&E's share of the aging power plants. The total peak capacity need for PG&E for 2009 is almost 30 percent of its total firm peak requirement, increasing to almost 75 percent by 2013 and remaining level through the remainder of the planning period.

Consistent with the loading order, this need is to be filled first with future programs designed to meet the CPUC's energy efficiency and demand response targets, by renewable resources, and by distributed generation and combined heat and power

181 *Aggregated Tables Report.*

resources. The preferred resource goals are shown in the tables.[182] For renewables, the goals shown are based on the accelerated target that goes beyond the 20 percent RPS requirement in statute.

Additional undesignated need beyond those levels should be filled through procurement, with the CPUC's rebuttable presumption as part of the open source procurement, through distributed generation resources, and through an appropriate level of short term and spot market sales and purchases.

These preferred resources represent approximately 30 percent of PG&E's firm peak requirement identified for PG&E in 2009, declining to near 20 percent in 2012, then increasing slowly to almost 30 percent at the end of the forecast period.

Though targets have not yet been established, the Energy Commission has recommended that the CPUC and Energy Commission establish targets for distributed generation and combined heat and power resources by the end of 2006. When these targets are established, these need tables should be updated to reflect the targets, resulting in an increase in the preferred resources.

7.2. SCE Resource Plan and Range of Need

7.2.1. Preferred Resources

7.2.1.1. Energy Efficiency

SCE provided two different forecasts of energy efficiency in its submittals. The first is the reference case required by the Energy Commission. SCE expressed concern that the required efficiency goals are not reliably achievable and, therefore, submitted an alternative resource plan with an energy efficiency forecast based on its 2004 long-term procurement plan.[183]

In its comments, SCE reports that it has "included the required levels of energy efficiency and demand response in its Reference Case."[184] SCE expresses doubt about meeting the adopted goals beyond 2011. "There is significant uncertainty, however,

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[182] The demand response goal for 2007 and beyond is 5 percent of the peak demand in the IOU distribution service area.

[183] Comments of Southern California Edison Company to the scenarios filed with the California Energy Commission for the 2005 Integrated Energy Policy Report, April 1, 2005., p.2.

concerning whether these levels of EE and DR can be attained within the current cost-effectiveness guidelines."[185] SCE believes there is no analysis to support levels of efficiency beyond what it terms "maximum achievable potential." SCE further comments that "directing SCE to implement a procurement plan based on the levels of EE and DR assumed by the Energy Commission could unnecessarily and unreasonably expose ratepayers to significant reliability and cost risk."[186] These same points are reiterated in SCE's comments on the June 29 Resource Plan Summary Assessment Report workshop.

In developing the efficiency goals, staff considered various limiting factors including constraints to ramping up program funding and the trend in market saturations for various measures. The statewide goal reflected the lower end of the range for economic potential presented in the Xenergy potential report.[187] Staff translated the statewide goals into utility-specific targets by applying a baseline ratio of IOU savings per dollar of expenditure to each IOU's share of relative program funding.

Recognizing the uncertainty and disagreement over the underlying assumptions used to calculate the maximum achievable savings potential, the adopted CPUC decision adjusted the goals to "reasonably bound the savings goals trajectory at either end of the forecast period, based on the best study information available to date."[188] Staff believes this adjustment took both market realism and judgment about future cost-effective efficiency potential into account.

SCE proposes an alternate case to the goals based on its 2004 long Term procurement plan that uses utility-specific analysis of its "maximum reliably achievable potential" for energy efficiency. This is the level that SCE believes is "the appropriate level to include for procurement planning purposes."[189] The major reason for the

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[184] *id.* at p. 6.

[185] *Ibid.*

[186] *Id.* at p. 7.

[187] *RPSA Report*, p. 14. See also *California's Secret Energy Surplus: The Potential for Energy Efficiency Programs in California*, prepared by Xenergy for the Energy Foundation and the Hewlitt Foundation, September 2002 [http://www.ef.org/documents/Secret_Surplus.pdf].

[188] D.04-09-050, p.26

[189] SCE, April 7, 2005, p.7.

difference in projected savings in this case is a steep decline in the annual increments of uncommitted savings, coupled with the end of committed savings in 2011. SCE believes that the marketplace for some energy efficient technologies will become saturated in the later years of the forecasting period. Additional savings will require newer technologies for the marketplace. SCE's alternate case will fall below the adopted goals (adjusted to generation level) by approximately 1,448 GWh and 289 MW in 2013.[190]

SCE disagreed with staff's assumption that it is likely that PGC funding will be available after 2011.[191] It notes that PGC funding of energy efficiency ends on January 1, 2012, by statute. "At this time, neither SCE nor the CEC has any basis for assuming that will be modified. Consequently, SCE must assume that PGC funding will terminate at the end of calendar year 2011. From a reporting perspective SCE has merely transferred PGC funded program activities into the "uncommitted" or unfunded category in accordance with CEC's definitions of committed and uncommitted".[192]

Staff questioned SCE's assumption that it will be possible to add 970 new GWh in the first year of a new program cycle.[193] SCE responded by reporting a similar ramp-up between its 2003 program year and its current 2004-2005 program years. SCE also reported exceeding 2004 goals and expects to exceed its 2005 goals. Additional energy efficiency activities aimed at reducing peak demand by 37.5 MW were authorized for the summer of 2005. Further, on June 1, 2005, SCE filed Application 05-06-015 requesting funding for a portfolio of programs targeted at exceeding the 970 new GWh referenced in this forecast.[194] Staff based its original conclusion on 28 years of historic data. Staff acknowledges that SCE has reported 984 GWh of savings for 2004, up from 499 GWh in 2003. These savings, however, have not yet been verified.

In its June 1 filing to the CPUC, SCE put together a highly diverse portfolio of programs for 2006-2008; only one program accounts for more than 10 percent of the portfolio savings. Over the three-year period, SCE projects 4,071 GWh in savings, 130

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[190] *RPSA Report*, p. 35 and Table 2-16.

[191] *RPSA Report*, p.30.

[192] SCE June 25 workshop comments, p.6.

[193] *RPSA Report*, p.30.

[194] SCE June 25 workshop comments, p.6.

percent of CPUC goals, and 784 MW, or about 108 percent of the peak savings goal. All the IOU peer review groups, however, expressed concern that without more emphasis on developing new programs, promoting comprehensive savings, and minimizing lost opportunities, meeting the 2009-2013 goals would be difficult.

The Energy Commission believes that SCE's long-term planning and procurement should be based on the targets established at the CPUC that consider statutory directives. On September 29, 2005, Governor Schwarzenegger signed into law Senate Bill 1037 (Chapter 366, Statutes of 2005, Kehoe) that clearly directs a primary focus on energy efficiency. While some of the concerns raised by SCE may be valid, these issues should be addressed through the monitoring and evaluation of approved efficiency programs and through future efficiency proceedings at the CPUC that will establish funding for programs for 2009 and later years and will adjust the efficiency targets as appropriate.

The Energy Commission is including the uncommitted portion of the current CPUC-adopted energy efficiency targets within the preferred resource category in the range of need tables.

7.2.1.2. Demand Response

SCE "generally agrees with the [RPSA] Report's conclusions with respect to demand response" but criticizes the report for failing "to address the impact of the fundamental disconnect between the CPUC's definition of its quantitative goals for demand response and the ability of current portfolios of price responsive programs to meet such goals during the 2006-2008 program cycle."[195]

SCE's comments, drawn from its Application 05-06-008 to the CPUC, raise a number of issues regarding the goals, including the need to pursue a "portfolio approach" of both price-sensitive and reliability demand response programs, the need to make the goals reflective of the proportion of customers to whom those program options were available (and thus which programs could be counted toward the goals), and the definition of demand response.

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[195] SCE's written comments to California Energy Commission's "Investor-Owned Utility Resource Plan Summary Assessment" Report, July 22, 2005 Page 8.

From a resource planning perspective, it makes sense to continue to distinguish between emergency "reliability" demand response programs and price-sensitive demand response programs that are counted toward demand response goals. The "portfolio approach" recommendation would only shift resources from one line of the table to another. Since the purpose of aggressive demand response goals was to encourage the addition of new, price-responsive programs and tariffs, using preexisting reliability resources to count toward those goals is inconsistent with its original intent.

The original DR goals were intended to include all customer groups, including those that did not have interval meters in 2003. D.03-06-032 and D.03-06-036 both anticipated that the goals would provide incentives for the IOUs to expedite both the development of price-responsive DR for large customers and the installation of interval meters for small customers. SCE's proposals to alter the goals to reflect slower progress than originally envisioned are properly being addressed through its Application 05-06-008 at the CPUC. The Energy Commission is including the current goals in the preferred resource category, with the understanding that this amount should be adjusted if the CPUC decides to revise the goals.

7.2.1.3. Renewables

SCE's four resource plan scenarios include three different levels of renewable resources, all of which include a minimum of 20 percent renewable energy by 2010. It built the same renewable portfolio in its reference case and no transmission case, which reaches 20 percent by 2007 and maintains that percentage through 2016. SCE's alternate case achieves about the same percentages as the reference case, but its renewables portfolio must include more than 120 percent of the amount of eligible renewable energy by 2016. This happens because the alternate case has different assumptions than the reference case: lower existing renewable QF generation and higher retail sales (because of lower assumptions about community choice aggregation load and energy efficiency resources). SCE's accelerated renewable case makes the same assumptions as the reference case for existing renewable QFs and retail sales, but its renewables portfolio over the period 2006 through 2016 must include close to three and one-half times the amount of eligible renewable energy to meet the higher goal of 31 percent by 2016.[196]

SCE states that its renewable resource assumptions to meet the 20 percent by 2010 goal are reasonable, but actual resources procured will be "the least cost best fit option[s] available during the planning period."[197] Staff found the renewable development assumptions used in these plans to be plausible after comparing the plans by technology and location to the remaining technical potential in the *2003 Renewable Resources Development Report.*[198]

The Energy Commission's 2016 target of 31 percent for SCE's accelerated renewables case requires SCE "to procure an additional 9,000 GWh of renewable power annually above what is currently required by statute and planned for by SCE." SCE's accelerated renewable case assumes 1,900 MW more eligible renewable capacity than in the reference case, plus some associated new transmission lines and upgrades.[199] Staff found the renewable development assumptions used in this case also to be plausible, based on technological potential.

SCE estimated the costs of the accelerated renewables case to be $1.2 billion more than the reference case (net present value of 2006-2016; in 2006 dollars, a 10.5 percent discount rate). SCE also expressed this cost increase as an "inflation-adjusted average of annual scenario costs per megawatt-hour" of $2.10 per MWh in 2006 dollars.[200] In its comments on the *RPSA Report*, which characterized SCE's cost estimates as "admittedly incomplete," SCE defended its cost estimate as providing "sufficient data and components essential to be able to make a comparison between the provided scenarios."[201]

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[196] SCE, April 1 filing, p. 3; *RPSA Report*, p. 47.

[197] SCE, April 1 filing, p. 9.

[198] *RPSA Report*, pp. 47-48. See also *Renewable Resources Development Report*, California Energy Commission, publication 500-03-080F, November, 2003.

[199] SCE, April 1 filing, p. 13.

[200] SCE, April 1 filing, p. 15.

[201] SCE written comments to California Energy Commission's "Investor-Owned Utility Resource Plan Summary Assessment" Report, July 22, 2005, p.18.

The Energy Commission has decided to use the generic renewable energy and capacity values developed by SCE for the accelerated renewables case as the preferred renewables identified in the range of need tables. The Energy Commission recognizes that this scenario was based on a different demand forecast, so the resulting trajectory of that level of future purchases would not be 35 percent of demand in 2020. Nonetheless, the primary purpose of identifying a preferred level of renewable resources on the need tables is to avoid procuring so much in non-preferred resources that renewable purchases to meet future targets are precluded. Therefore, the Energy Commission considers the generic renewable resources identified by SCE in its accelerated renewables case, which all parties agreed would be technically achievable (though at uncertain costs), provide a useful benchmark. The Energy Commission invites comments on this approach and recommendations on alternate approaches for determining the amount of preferred renewables to identify in the need tables.

7.2.1.4. Distributed Generation

In its assessment, staff could not determine what SCE's assumptions were regarding future DG. In its July 22 comments, SCE clarified its forecast:

> SCE believes the CEC forecast for industrial local private supply may be high. There is an ongoing shift from manufacturing to non-manufacturing activity in the local economy. Based on this shift, the SCE forecast includes a slow but steady decline in industrial energy use. The CEC forecast shows a slow but steady increase in industrial energy use. The difference in industrial outlooks probably accounts for the difference in the industrial private supply between the two forecasts.[202]

In the *Draft Energy Report,* the Energy Commission recommends that "by the end of 2006, the Energy Commission and CPUC should work collaboratively to translate this goal [of 5,400 MW of CHP statewide by 2020] into yearly procurement targets for IOUs."[203] Once these goals are established, the CPUC should incorporate them into the preferred resource category on the need tables and correspondingly reduce the amount of undesignated need.

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[202] *Id.* at pp. 21-22.

[203] *Draft Energy Report*, p. 67.

7.2.2. Energy Resource Needs

The energy range of need for SCE is shown in Appendix B Tables B-7, B-8, and B-9 for the base, low and high revised staff forecasts, respectively, and is described in the sections below.

7.2.2.1. Utility-Controlled Resources

SCE's resource plans included the annual energy for utility-controlled nuclear, fossil, and hydroelectric resources. For these resources, SCE's plans assume relatively flat levels of generation throughout the forecast period. SCE's reported utility-controlled resources total between 30,000 and 33,000 GWh for the years 2009 through 2016.

7.2.2.2. Contractual Resources

SCE's resource plans show a significant drop in contractual resources throughout the forecast period, with the largest drop between 2011 and 2012 as the almost 20,000 GWh of DWR contracts reported for 2009 and 2010 decline to less than 17,000 GWh in 2011 and to zero in 2012.

SCE projected energy resources from QF and renewables contracts to remain relatively constant, with the energy supply from these contracts of approximately 25,000 GWh for QF contracts and slightly less than 3,000 GWh for renewables contracts throughout the period. Energy supplies from other existing bilateral contracts decline during the planning period, going from more than 6,000 GWh in 2009 and 2010 to 1,750 GWh in 2011, and approximately 1,400 GWh for 2012 through 2016.

While the aggregated data tables counted short term and spot market purchases as part of the total existing and planned resources, the Energy Commission has chosen to consider these purchases as part of the need to be filled by SCE.

7.2.2.3. Energy Range of Need

The balance of energy demand versus existing and planned resources for SCE show relatively modest energy needs across the three demand forecasts of 1 to 3 percent of the total energy requirement in 2009 to 35 to 40 percent by 2016. As discussed above, the Energy Commission is adding an increment to this balance to ensure adequate procurement to allow for the orderly replacement of retiring aging power plants by 2012. SCE's full energy share for aging plant replacement is slightly more than 12,500

GWh. The aging plant replacement increment is stepped up to this full amount from 2009 through 2012.

The resulting total energy need for SCE ranges from approximately 4,500 to 6,000 GWh in 2009 increasing to 45,000 to 50,000 GWh in 2016. These values represent between 5 and 7 percent of the total energy requirement in 2009 and about 50 percent in 2016.

In addition to developing the total range of need, the Energy Commission is reporting on the amount of preferred resources that the utilities should plan to obtain consistent with the loading order. The Energy Commission recognizes that ongoing and future proceedings at the CPUC may result in adjustments to these numbers, but recommends that the authority the CPUC grants for open source procurement be adjusted to ensure that these preferred resources are not crowded out in the future.

The uncommitted energy efficiency savings included in the preferred resources are based on the estimates provided by SCE based on the targets established by the CPUC in D.04-09-060, adjusted to account for the inclusion of committed energy efficiency programs through 2008 in the revised demand forecast. These savings ramp up from less than 900 GWh in 2009 to almost 9,000 GWh in 2016.

As discussed above, the Energy Commission includes in the preferred resources category renewable resources consistent with the accelerated goal of 35 percent renewables by 2020 that the Energy Commission recommended for SCE in the *2004 Energy Report Update*. While the CPUC cannot under current law require RPS procurement beyond 20 percent, the Energy Commission places great weight on the rebuttable presumption for renewable resources in any RFO seeking generation resources established by the CPUC in D.04-12-048, despite SCE's lack of specificity about how it intends to implement this policy directive.

As directed by the Energy Commission, SCE filed an accelerated renewables resource plan scenario aiming at 35 percent renewable resources by 2020. While the trajectory in this resource plan is not based on the revised staff demand forecast, it is the most detailed information in the record on the possible path that SCE could follow to meet the accelerated targets. Therefore, the Energy Commission is using the generic renewable energy needs identified by SCE in its resource plan as a placeholder to ensure that SCE will be able to purchase adequate renewables to meet the enhanced goals should they be enacted into law. The Energy Commission invites comments on this approach and recommendations on alternate approaches for determining the amount of preferred renewables in the need tables.

For the low and base demand cases for SCE, these preferred resources represent slightly more than the total need for 2009. For the high demand cases, the preferred resources are more than to 90 percent of the total energy needs identified for SCE in 2009. SCE's total need increases significantly between 2009 and 2012, with the increasing increment for aging plant replacement between 2009 and 2012, because of the major expiration of DWR contracts by 2012. The share of total need represented by preferred resources declines to less than 30 percent by 2012 for all three demand forecast cases. The share then slowly increase to near 45 percent by 2016.

Though targets have not yet been established, the Energy Commission has recommended that the CPUC and Energy Commission establish targets for distributed generation and combined heat and power resources by the end of 2006. When these targets are established, these need tables should be updated to reflect the targets, resulting in an increase in the preferred resources.

7.2.3. Capacity Resource Needs

The capacity range of need for SCE is shown in Appendix B Tables B-10, B-11, and B-12 for the base, low and high revised staff forecasts, respectively, and is described in the sections below.

7.2.3.1. Utility-Controlled Resources

SCE's resource plans include public tables providing the annual capacity for utility-controlled nuclear, fossil, and hydroelectric resources for the years 2009 through 2016.[204] These tables show a nearly constant level of capacity available from these existing and planned resources, the only change being an 11 MW reduction in fossil capacity by 2016. The Energy Commission is including these resources in its calculation of the range of need.

7.2.3.2. Contractual Resources

For contractual resources, the public capacity tables in SCE's resource plans only included the DWR contracts. The aggregated SCE planning area capacity tables also

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[204] The public tables filed by SCE were published in Appendix B of the *RPSA Report*.

show totals for QF contracts (which are not held by other LSEs within SCE's planning area, so this total is also SCE-specific), renewable contracts, and other bilateral contracts.

The DWR contracts assigned to SCE decline rapidly starting in 2009, with total capacity declining from 3,217 MW in 2009 and 2010 to 2,415 MW in 2011, and disappearing entirely in 2012. SCE projected QF capacity to remain constant throughout the period at 3,211 MW. These IOU-specific contractual resources consistently represent more than 65 percent of the capacity of the contractual resources for each year in the capacity tables for SCE's planning area.

The aggregated tables show relatively steady capacity from renewable contracts and other bilateral contracts through the planning period, going from a combined total of 1,666 MW in 2009 to 1,704 MW in 2016. Due to confidentiality constraints, these values include contracts held by POUs in the SCE planning area and a share of contracts held by ESPs. As discussed above, the Energy Commission intends in the final version of this report to subtract the POU data from these totals, resulting in a distribution service area estimate for the renewables contracts and other bilateral contracts.

While the aggregated data tables counted short-term and spot market purchases as part of the total existing and planned capacity, the Energy Commission has chosen to consider these purchases as part of the need to be filled by SCE.

7.2.3.3. Capacity Range of Need

As described in more detail above, the need for each forecast was calculated by subtracting the identified resources and existing interruptibles capacity from the forecast demand and then adding sufficient capacity to account for SCE's share of the aging power plants. The balance of peak energy demand and existing and planned resource capacity shows that SCE's unmet needs for 2009 are almost half of its total firm peak requirement, increasing to almost 90 percent by 2012 and remaining level through the remainder of the planning period.

Consistent with the loading order, this need is to be filled first by future programs designed to meet the CPUC's energy efficiency and demand response targets.

These goals are shown in the tables.[205] For renewables, the goals shown are based on the accelerated target that goes beyond the 20 percent RPS requirement in statute.

Additional undesignated need beyond those levels should be filled through procurement, with the CPUC's "rebuttable presumption" as part of the open source procurement, through distributed generation resources, and through an appropriate level of short-term and spot market sales and purchases. These preferred resources represent approximately 20 percent of SCE's firm peak requirement throughout the forecast period.

Though targets have not yet been established, the Energy Commission has recommended that the CPUC and Energy Commission establish targets for distributed generation and combined heat and power resources by the end of 2006. When these targets are established, these need tables should be updated to reflect the targets, resulting in an increase in the preferred resources.

7.3. SDG&E Resource Plan and Range of Need

7.3.1. Preferred Resources

7.3.1.1. Energy Efficiency

SDG&E believes that the goals authorized by the CPUC in D.04-09-060 for 2006 through 2008 are aggressive but achievable. For the years beyond 2009, however, it believes the CPUC's stated goals will be difficult to attain. D.04-09-060 acknowledges that the adopted trajectory of GWh savings goals for SDG&E is 118 percent of the cumulative maximum achievable potential that was identified in background analysis. SDG&E expects that before 2009, the CPUC will reevaluate these goals, and that this reevaluation will likely result in more realistic and achievable goals for SDG&E.[206] However, SDG&E did not present a lower level of energy efficiency savings in any of its cases.

With regard to the feasibility of the 2006-2008 energy efficiency savings, the preliminary savings estimates exceed target levels. Results for 2003 and 2004 show that

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[205] The demand response goal for 2007 and beyond is 5 percent of the peak demand in the service territory.

[206] SDG&E April 1 filing, p.8,9 and June 29 transcript at p. 32.

SDG&E did not meet its goals for GWh in those years but did meet the MW goal in 2004. A review of the proposed energy efficiency programs by the peer review group (CPUC, Energy Commission, ORA, and others) stated that the near-term goals are attainable, but that the longer-term goals would be much harder to reach. A consultant report revealed potential problems in ramping up programs to target funding levels, lack of contractors and vendors to support the programs, and the role of participants outside the direct control of SDG&E.[207]

IEP recommended that the numbers passed on to the CPUC for procurement be based on realistic, achievable inputs and not on stretch goals.[208]

SDG&E faces a m ore acute version of the same issue for all three IOUs. SDG&E's housing development is taking place in inland regions leading to much greater air conditioning needs than in the past. In light of this, SDG&E should be targeting energy efficiency programs that achieve peak impacts.

The 2006-2008 energy efficiency targets were included in the demand forecast, and all parties agreed they were aggressive but achievable. Parties agree that SDG&E's post-2009 goals are somewhat unrealistic and will be revisited and revised in the next CPUC proceeding when new cost-effectiveness and program performance information is available. While the CPUC has acknowledged that the post-2009 goals for SDG&E are 118 percent of maximum achievable potential that was identified in background analysis, the CPUC has not yet revised those goals. As discussed above, the Energy Commission anticipates that the CPUC will adjust the range of need to reflect any changes in the energy efficiency goals. Therefore, in this transmittal report, the Energy Commission is using the currently adopted goals for SDG&E within the preferred resources.

7.3.1.2. Demand Response

In its Reference Case, SDG&E includes the annual load reduction targets set forth by the CPUC in D.03-06-032. These targets are designed to achieve load reductions from day-ahead programs equal to 4 percent of annual system peak load by 2006 and 5

[207] *RPSA Report*, p.23.

[208] Kelly, June 29 TR at 58.

percent of annual system peak load in 2007 and beyond. SDG&E removed these targets from its alternative scenario and has included only the load reductions from those programs with approved funding. Since programs have been modified over the past several years and since the Advanced Metering/Dynamic Pricing proceeding is engaged in redesigning programs, SDG&E did not feel it had either a track record or funding authorization to forecast achievable programs over the long term.[209] This results in about 200 MW less peak reduction by 2012 in the planning area, with program acceleration so that similar 400 MW reductions are reached by 2016.[210]

The Energy Commission is showing the current CPUC target of 5 percent of service territory load in 2007 and beyond as the amount of preferred demand response resources in the need tables. The Energy Commission recognizes that the CPUC may decide to revise those targets in its demand response proceeding and expects that the values in the need tables will be adjusted appropriately if new targets are adopted.

7.3.1.3. Renewable Energy

In SDG&E's April 1 filing, renewable energy targets are met in three of the four scenarios, with SDG&E failing to meet the required 20 percent of retail sales by 2010 in its no major transmission scenario. All other scenarios assume the development of a major transmission line to either SCE territory or the Imperial Valley. The reference case meets the 20 percent requirement by 2010 and holds that percent constant throughout the forecast period. The accelerated renewables case meets the target of 28 percent by 2016 but states that several factors would determine if this is feasible, including the availability, portfolio fit and cost of renewable energy; whether new transmission lines are built; and whether or not SDG&E can procure and count renewable energy credits for meeting this target.[211]

Staff noted that in the reference case and the alternative case, SDG&E assumes a doubling of renewable energy in its portfolio mix between 2009 and 2010 in order to

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[209] SDG&E April 1 filing, p.9.

[210] Aggregated Data Tables 27 and 29.

[211] SDG&E, April 1 filing, p. 3

meet the 20 percent target.[212] This is implausible without some major change such as a new transmission line or use of renewable energy credits. SDG&E states that these cases both assume the addition of a major transmission line and additional renewable projects that will take time to develop.

Staff found the renewable development assumptions used in these plans to be plausible by comparing the plans by technology and location with the remaining technical potential in the *2003 Renewable Resources Development Report*.[213] SDG&E demonstrated it plans to meet RPS requirements, but will probably need either major new transmission or renewable energy trading credits to attain the 2010 goal on time. SDG&E plans to submit a bulk transmission line to the CPUC in 2006. The Energy Commission supports the value of a new bulk line, as discussed below and in the *Draft Strategic Plan*. Renewable credits are also under active consideration.

The Energy Commission has decided to use the generic renewable energy and capacity values developed by SDG&E for the accelerated renewables case within the preferred renewables identified in the range of need table. The Energy Commission recognizes that this scenario was based on a different demand forecast, so the resulting trajectory of that level of future purchases would not be 33 percent of demand in 2020. Nonetheless, the primary purpose of identifying a preferred level of renewable resources on the need tables is to avoid procuring so much in non-preferred resources that renewable purchases to meet future targets are precluded. Therefore, the Energy Commission considers the generic renewable resources identified by SDG&E in its accelerated renewables case, which all parties agreed would be technically achievable (though at uncertain costs), provide a useful benchmark. The Energy Commission invites comments on this approach and recommendations on alternate approaches for determining the amount of preferred renewables to identify in the need tables.

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[212] *RPSA Report*, p. 57.

[213] *RPSA Report*, p. 59. See also *Renewable Resources Development Report*, California Energy Commission, publication 500-03-080F, November, 2003.

7.3.1.4. *Distributed Generation*

Staff's assessment of SDG&E's DG additions revealed that future DG additions were significantly less than historical monthly average additions of 1.2 MW from 2001-2004. This average was calculated using interconnection data from 2001-2004.[214]

SDG&E states that an analysis of historical interconnection data would be necessary to determine whether using data from this time period is appropriate for forecasting future DG additions. DG additions during and after the energy crisis and the addition of a few large projects could skew the monthly average and may not be indicative of future DG additions.[215]

In the *Draft Energy Report,* the Energy Commission recommends that "by the end of 2006, the Energy Commission and CPUC should work collaboratively to translate this goal [of 5,400 MW of CHP statewide by 2020] into yearly procurement targets for IOUs."[216] Once these goals are established, the CPUC should incorporate them into the preferred resource category on the need tables and make a corresponding change in the undesignated need portion of these tables.

7.3.2. Energy Resource Needs

The energy range of need for SDG&E is shown in Appendix B Tables B-13, B-14, and B-15 for the base, low and high revised staff forecasts, respectively, and is described in the sections below.

7.3.2.1. *Utility-Controlled Resources*

SDG&E's resource plans include the annual energy for utility-controlled nuclear, fossil, and hydroelectric resources. For nuclear resources, SDG&E proposes to revise its 20 percent ownership portion, 430 MW, of the San Onofre Nuclear Generation Station (SONGS).[217] SDG&E has opted not to participate in the proposed replacement of the SONGS steam generators and is awaiting a CPUC decision in A.04-02-026. SDG&E assumes in its reference case that the CPUC will allow SDG&E to not participate and

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[214] *RPSA Report,* p.67.

[215] SDG&E July 22 comments p. 9.

[216] *Draft Energy Report*, p. 67.

[217] SDG&E, April 1, p. 2

reduce its ownership share to 14 percent of SONGS. If the replacements go forward on SCE's proposed schedule, these changes will occur in 2009 for Unit 2 and 2010 for Unit 3. The result is a drop in nuclear energy in the resource plan from more than 3,100 GWh in 2009 to approximately 2,500 GWh through the remainder of the planning period. The CPUC is expected to rule on SONGS before completion of the 2006 long term procurement proceeding, and any changes necessary to this portion of the need table should be made based on that ruling.

SDG&E's plans assume relatively flat levels of hydro and fossil generation throughout the forecast period. SDG&E shows small negative hydro energy resources of approximately 15 GWh throughout the forecast period. SDG&E relies on hydro pumped storage that, on average through the year, results in energy expenditures while offering advantages in terms of available capacity during peak times. The fossil energy resources total approximately 4,000 GWh throughout the forecast period. Overall, SDG&E's reported utility-controlled resources start at 7,100 GWh in 2009, and then range between 6,200 and 6,700 GWh for the years through 2016.

7.3.2.2. Contractual Resources

SDG&E's resource plans show a significant drop in contractual resources throughout the forecast period, with the largest drop between 2010 and 2011 due to the expiration of more than 1,500 GWh of DWR contracts. SDG&E projects energy resources from QF contracts to remain relatively constant throughout the period, with the energy supply from these contracts slightly more than 1,700 GWh. Energy supplies from renewable contracts and other bilateral contracts decline throughout the planning period, going from a combined total of slightly more than 6,000 GWh in 2009 to approximately 2,500 GWh in 2016.

While the aggregated data tables counted short-term and spot market purchases as part of the total existing and planned resources, the Energy Commission has chosen to consider these purchases as part of the need to be filled by SDG&E.

7.3.2.3. Energy Range of Need

The balance of energy demand and existing and planned resources for SDG&E show relatively modest energy needs across the three demand forecasts of approximately 10 percent of the total energy requirement in 2009 to almost half by 2016. As discussed above, the Energy Commission is adding an increment to this balance allowing adequate procurement for the orderly replacement of the retiring aging power plants by 2012. SDG&E's full energy share for aging plant replacement is almost 4,400 GWh. The aging plant replacement increment is stepped up to this full amount from 2009 through 2012. The resulting total energy need for SDG&E ranges from approximately 3,000 to 3,250 GWh in 2009 to 14,000 to 14,700 GWh in 2016. These values represent slightly more than 15 percent of the total energy requirement in 2009 and approximately 70 percent in 2016.

In addition to developing the total range of need, the Energy Commission is reporting the amount of preferred resources that the utilities should plan to obtain consistent with the loading order. The Energy Commission recognizes that ongoing and future proceedings at the CPUC may result in adjustments to these numbers, but is recommends that the authority the CPUC grants for open source procurement be adjusted to ensure that these preferred resources are not crowded out in the future.

The uncommitted energy efficiency savings included in the preferred resources are based on the estimates provided by SDG&E based on the targets established by the CPUC in D.04-09-060, adjusted to account for the inclusion of committed energy efficiency programs through 2008 in the revised demand forecast. These savings ramp up from approximately 140 GWh in 2009 to more than 2,000 GWh in 2016.

As discussed above, the Energy Commission is including in the preferred resources category renewable resources consistent with the accelerated goal of 33 percent renewables by 2020 that the Energy Commission recommended for SDG&E in the *2004 Energy Report Update*. While the CPUC cannot under current law require RPS procurement beyond 20 percent, the Energy Commission places great weight on the rebuttable presumption for renewable resources s in any RFO seeking generation resources established by the CPUC in D.04-12-048, despite SDG&E's lack of specificity about how it intends to implement this policy directive.

As directed by the Energy Commission, SDG&E filed an accelerated renewables resource plan scenario aiming at 33 percent renewable resources by 2020. While the trajectory in this resource plan is not based on the revised staff demand forecast, it is the most detailed information in the record on the possible path that SDG&E could follow to meet the accelerated targets. Therefore, the Energy Commission is using the generic renewable energy needs identified by SDG&E in this resource plan as a placeholder to ensure SDG&E will be able to purchase adequate renewables to meet the enhanced goals, should they be enacted into law. The Energy Commission invites comments on this approach and recommendations on alternate approaches for determining the amount of preferred renewables to identify in the need tables.

These preferred resources represent less than 25 percent of the total energy needs identified for SDG&E in 2009. Because SDG&E's accelerated renewables resource plan included a major jump in renewables resources in 2010 on the assumption that additional transmission would become available, the preferred resources represent approximately 50 percent of the total need in 2010. The portion of total need represented by the preferred resources then drops to near 30 percent by 2012, and then increases slowly to approximately 45 percent by 2016.

Though targets have not yet been established, the Energy Commission has recommended that the CPUC and Energy Commission establish targets for distributed generation and combined heat and power resources by the end of 2006. When these targets are established, these need tables should be updated to reflect the targets, resulting in an increase in the preferred resources and a decrease in the undesignated need portion of the tables.

7.3.3. Capacity Resource Needs

The capacity range of need for SDG&E is shown in Appendix B Tables B-16, B-17, and B-18 for the base, low and high revised staff forecasts, respectively, and is described in the sections below.

7.3.3.1. Utility-Controlled Resources

SDG&E's resource plans included public tables providing the annual capacity for utility-controlled nuclear, fossil, and hydroelectric resources for the years 2009 through 2016.[218] These tables show a nearly constant level of capacity available from these existing and planned resources, the only change being a 66 MW reduction in nuclear capacity starting in 2010, based on SDG&E's reduced ownership share in SONGS. The Energy Commission is including these resources in its calculation of the range of need.

[218] The public tables filed by SDG&E were published in Appendix B of the *RPSA Report.*

7.3.3.2. Contractual Resources

For contractual resources, the public capacity tables in SDG&E's resource plans only included the DWR contracts. The aggregated SDG&E planning area capacity tables also show totals for QF contracts (which are not held other LSEs in the SDG&E planning area, so this total is also SDG&E-specific), renewable contracts, and other bilateral contracts.

The DWR contracts decline rapidly after 2011, with a total capacity declining to 2,103 MW for 2009 and 2010, declining to 718 MW in 2011 and 26 MW in 2012 and 2013. No DWR contracts assigned to SDG&E remain in place after 2013. SDG&E projected QF capacity to remain relatively constant throughout the period, with the 2009 QF capacity of 2,559 MW declining only to 2,472 MW in 2016. These IOU-specific contractual resources consistently represent more than 60 percent of the capacity of the contractual resources in the capacity tables for SDG&E's planning area.

The aggregated tables show a small decline in capacity from renewable contracts and other bilateral contracts through the planning period, going from a combined total of 840 MW in 2009 to 766 MW in 2016. Due to confidentiality constraints, these values include a share of contracts held by ESPs. There are no POUs in SDG&E's planning area.

While the aggregated data tables counted short-term and spot market purchases as part of the total existing and planned capacity, the Committee has chosen to consider these purchases as part of the need to be filled by SDG&E.

7.3.3.3. Capacity Range of Need

As described in more detail above, the need for each forecast was calculated by subtracting the identified resources and existing interruptibles capacity from the forecast demand, and then adding sufficient capacity to account for SDG&E's share of the aging power plants. The balance of peak energy demand and existing and planned resource capacity shows that SDG&E's total need for 2009 are approximately 20 percent of their total firm peak requirement, increasing to more than 90 percent by 2010 and remaining level through the remainder of the planning period.

Consistent with the loading order, this need is to be filled first by future programs designed to meet the CPUC's energy efficiency and demand response targets.

These goals are shown in the tables.[219] For renewables, the goals shown are based on the accelerated target that goes beyond the 20 percent RPS requirement in statute.

Additional undesignated need beyond those levels should be filled through procurement, with the CPUC's rebuttable presumption as part of the open source procurement, through distributed generation resources, and through an appropriate level of short-term and spot market sales and purchases.

These preferred resources represent approximately 40 percent of SDG&E's total peak need identified for SDG&E in 2009. As with energy resources, this number spikes to more than 50 percent in 2010 with the assumed addition of new transmission allowing a significant increase in renewable resources. Preferred resources then remain between 20 and 30 percent of total peak need from 2011 through 2016.

Though targets have not yet been established, the Energy Commission has recommended that the CPUC and Energy Commission establish targets for distributed generation and combined heat and power resources by the end of 2006. When these targets are established, these need tables should be updated to reflect the targets, resulting in an increase in the preferred resources and a decrease in the undesignated need values.

8. Natural Gas Demand, Supply, Prices, Infrastructure Needs, and Policies

The Committee assessed natural gas demand, supply, price, and infrastructure issues. These issues will significantly affect California's energy future; as a result, related policy choices will be an important tool in meeting future energy challenges.

8.1. Preliminary Staff Assessment

In order to assist in the Committee's consideration of these issues, the Energy Commission staff prepared a natural gas demand forecast, using the North American Regional Gas – MarketBuilder model (NARG-MB).[220] The results indicate that natural gas demand in California is expected to grow at a rate of 0.7 percent per year, from 6.5

[219] The demand response goal for 2007 and beyond is 5 percent of the peak demand in the service territory.

[220] *Preliminary Reference Case in Support of the 2005 Natural Gas Market Assessment*, Energy Commission Staff, June, 2005, p. 1

billion cubic feet per day (cfd) in 2006 to slightly under 7 billion cfd in 2016.[221] Demand in the commercial and residential sectors will grow at 2 percent and 1.4 percent respectively during the next decade, but this growth will be offset by declining demand and slower growth in gas consumption by industrial users and power generators.[222] Because the market from which California obtains its natural gas extends across the entire continent, the staff assessment also included projections for natural gas consumption and growth rates throughout North America.[223]

Generally speaking, natural gas consumption is expected to rise annually by 1.7 percent in the United States over the forecast period, with most of the increase due to growth in the power generation sector in the eastern portion of the United States.[224] Total consumption will likely increase from slightly less than 60 billion cfd to approximately 70 billion cfd by 2016.[225]

Energy Commission staff also conducted an assessment of natural gas supply, using information from the National Petroleum Council, which recently evaluated the North American gas market, as well as the United States Geological Survey, the Mineral Management Service, and other industry and governmental groups. This assessment addressed gas supplies available to North American markets generally (increasing from approximately 80 billion cfd in 2006 to slightly more than 90 billion cfd in 2016), and projected gas supplies by basin to California (increasing from 5.4 billion cfd in 2006 to 5.9 billion cfd in 2016). The report also included an assumption that the liquefied natural gas (LNG) portion of North American natural gas supply would increase by 8.7 percent during the forecast period.[226]

With respect to prices, Energy Commission staff expects a general initial increase in wellhead prices, followed by price decreases several years into the forecast period, due to the introduction of new supplies. However, by the end of the forecast period,

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221 *Id*. at p. xi

222 *Id.* at p. 7

223 *Id*. at p. x

224 *Id*. at p. 5

225 *Ibid*.

226 *Id*. at p. 27

prices would be above current levels.[227] End-use prices in California generally mirror this trend, with prices being highest for SDG&E customers and lowest for PG&E customers, although the gap will narrow over time.[228]

In evaluating infrastructure, Energy Commission staff addressed interstate and intrastate pipeline capacity and adequacy issues, but did not explicitly examine what infrastructure would be associated with additional LNG facilities.[229] Staff noted that there have been several major pipeline expansions during the past four years, resulting in an increase in receiving capacity from 6,901 million cfd in 2001, to 7,970 million cfd in 2004.[230] Given these expansions, and assuming that an LNG facility is built on the West Coast, staff concluded that interstate pipeline capacity is sufficient to meet California's natural gas needs on an annual basis.[231] However, staff indicated that interstate capacity is not sufficient to meet daily needs, and that either cold weather or interstate pipeline disruptions can result in shortfalls. At those times, the state must rely on its fairly significant storage capacity to meet demand.[232]

Staff also assessed the delivery capacity of the natural gas pipelines – the ability of the pipelines to actually deliver natural gas to California customers – and concluded that interstate pipeline actual flows into California will generally increase, and that expansion of the TGN (Transportadora de Gas Natural) Pipeline that connects Baja California to the San Diego region would be cost-effective if the LNG projects in Baja California are built.

With respect to natural gas policy issues, staff stated that it does not have immediate concerns about reliability.[233] However, staff notes that consumers will likely pay a higher price for natural gas. Staff identified several policy options, including investments in energy efficiency, development of supplemental supplies, and ensuring

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[227] *Id*. at p. 41

[228] *Id*. at p. 43

[229] *Id*. at p. 33

[230] *Id*. at p. 34

[231] *Ibid*.

[232] *Id*. at p. 35

[233] *Id*. at p. 49

that needed infrastructure is identified in a timely manner.[234] Staff also pointed out that reducing peak electrical demand will reduce a small summer peak in natural gas demand because of the use of natural gas in California's electrical generating system.[235]

8.2. Utility Assessments

In addition to the staff assessment, the three IOUs offered assessments of natural gas issues.[236] With respect to forecasted demand, PG&E reported that its 10-year forecast for the residential sector was within 1 percent of the staff forecast.[237] There were some minor data issues, but they did not have a significant effect on the forecasts. On the non-residential side, PG&E's forecast differed significantly from staff's.[238] PG&E's forecast projects some growth in the early years of the forecast, but then shows stagnation and declining demand in the later years. PG&E attributes this to high natural gas prices and lack of growth in manufacturing; the only sector that PG&E believes will experience growth is oil refining; all others will not.[239] PG&E also notes that both consumption per customer and total number of customers are declining in those sectors.[240] Staff's forecast on the other hand, shows annual average growth rates of 1 percent.[241]

Sempra provided natural gas forecasts for both the Southern California Gas Company (SCG) and SDG&E service area. For SCG, Sempra's forecast for growth rates in the residential sector is similar to staff's, with the differences attributable to differing

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[234] *Id*. at p. 53

[235] *Id*. at p. 54

[236] There are three IOUs offering natural gas services to California customers – PG&E, SDG&E, and Southern California Gas Company (SCG). SCG and SDG&E share the same parent company -- Sempra Energy Utilities (Sempra) – and filed joint comments and made joint presentations on natural gas issues.

[237] 7/14/05, RT, p.70

[238] 7/14/05, RT, p. 74.

[239] *Id*. at pp. 75-76

[240] *Id*. at p. 77

[241] PG&E's Comments on CEC's Draft Gas Demand Forecast, Slide 5; Preliminary Reference Case in Support of the 2005 Natural Gas Market Assessment, Energy Commission Staff, June, 2005, p. 11

assumptions about long-term energy efficiency savings. Sempra included savings mandated by the CPUC for a 10-year period, whereas Energy Commission staff only included savings from programs that are currently funded.[242] The difference in growth rate assumptions is approximately 0.1 percent per year.[243] On the non-residential side, the staff and Sempra forecasts differ more than on the residential side, but the difference is primarily due to the differing assumptions about energy efficiency savings over time discussed above.[244] However, here the difference in growth rate assumptions is 1.9 percent per year.[245] Finally, the staff forecast for demand growth in the electrical generation market segment is higher than Sempra's.[246]

For SDG&E, the two residential forecasts use similar growth rates, but the staff forecast shows a higher level of demand[247]. On the non-residential side, staff assumed an annual growth rate 1.3 percent higher than that assumed by Sempra, due primarily to the inclusion by Sempra of longer-term energy efficiency savings that staff did not include.[248] Finally, there are significant differences in the growth rate assumptions for the electrical generation sector, with staff showing an annual growth rate of 4.6 percent, compared to Sempra's assumption of 1.7 percent.[249]

PG&E also presented comments on natural gas supply and infrastructure needs. PG&E is concerned because it believes that natural gas prices will continue to increase.[250] As a result, PG&E supports implementation of energy efficiency programs and development of renewable resources to moderate the effect of these price

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242 7/14/05, RT, pp. 83-84

243 Comments of Southern California Gas Company and San Diego Gas and Electric Company on the CEC Staff's Preliminary Natural Gas Assessment and Policy Issues Report (Sempra Presentation), Natural Gas Demand and Supply Issues, slide 3

244 Sempra Presentation, Natural Gas Demand and Supply Issues, slide 4

245 *Ibid*.

246 Sempra Presentation, Natural Gas Demand and Supply Issues, slide 5

247 Sempra Presentation, Natural Gas Demand and Supply Issues, slide 7

248 *Id.* at slide 8

249 *Id*. at slide 9

250 7/14/05, RT, p. 267

increases.[251] PG&E also sees a benefit from increased supplies and believes the most promising new supplies are LNG and natural gas delivered via an Alaska pipeline.[252] Finally, PG&E believes that new infrastructure -- both storage and pipelines -- is needed, primarily to connect to new supplies of LNG entering the state.[253]

Sempra's comments on natural gas supply and price issues focused on the need to develop new supplies, especially LNG. Sempra is concerned about price volatility and the effect of high prices on certain industrial sectors. Sempra believes that to address these problems, the state should support the development of new supplies and actively promote LNG deliveries. Sempra also explained that it believes shippers should pay the costs of expanding "backbone" receipt facilities, unless benefits exceed costs, in which case the costs should be rolled into system rates. Finally, Sempra expressed support for the natural gas policy recommendations included in the *2003 Energy Report*.

8.3. Western States Petroleum Association (WSPA)

WSPA did not file written comments on natural gas issues, but did make an oral presentation at the July 14, 2005 hearing on staff's preliminary natural gas assessment and natural gas policy issues. In its comments, WSPA recommended that the Committee focus on reliability issues and stated that WSPA's policy is to support expanded natural gas exploration, development and production, maintenance of existing infrastructure and development of new infrastructure, and development of LNG facilities. WSPA stated that it believes natural gas demand may be greater than identified in the staff assessment.[254]

8.4. Committee Discussion

Based on the presentations at the July 14, 2005 hearing and comments received on the preliminary staff forecast, the Committee directed staff to make several changes in the assumptions underlying the natural gas price and supply forecast. The major

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[251] PG&E's Comments on Committee Hearing on the Staff's Preliminary Natural Gas Assessment and Policy Issues, Robert Howard, slide 3

[252] *Id*. at slide 5

[253] 7/14/05, RT, pp. 267-268

[254] 7/14/05, RT, p. 90

changes were the demand elasticity parameters for California markets, the ability for LNG receiving facilities in the U.S. to expand beyond 2010 if they are economical to do so, and delaying the entry of natural gas supplies from the Alaskan and MacKenzie pipelines. The revised forecast was published in September 2005.[255]

The demand projections resulting from the NARG-MB model results differed slightly from the demand projections developed in the Demand Analysis Office of the Energy Commission due to differing economic-demographic factors such as the population growth in the state. The input parameters in the NARG-MB model were changed to be consistent with assumptions used by other Energy Commission offices, reflecting the Department of Finance population growth rate estimates for California (as opposed to the DOE/EIA assumptions for the entire United States).

The preliminary reference case assumed that no LNG facility would expand above its current capacity, plus any additional capacity under construction, beyond the year 2010. This assumption was changed to include any economically viable expansion of LNG facilities beyond the year 2010. Further, based on more recently available market information, the time of availability of the MacKenzie pipeline and the Alaskan pipeline from Arctic resources was delayed. It was assumed that the MacKenzie pipeline would be constructed and be in operation in 2013, while the Alaskan pipeline would be available by the year 2016.

The Committee directed staff to make the above changes and provide the updated results at the hearing on the natural gas chapter of the *Draft Energy Report* that was held on October 7, 2005. At the hearing, PG&E filed testimony saying the staff generated price forecast for the Henry Hub estimates or the Lower 48 wellhead prices were reasonable compared to other private forecasts reviewed by PG&E. However, it commented that the natural gas end-use or retail prices in the PG&E service area were higher than its estimations. Based on PG&E comments, staff made further changes to the reference case. Changes included modifying the distribution costs in the pricing chain to be fixed at the tariff rate. The results of the revised reference case are discussed below.

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[255] *Revised Reference Case in Support of the 2005 Natural Gas Market Assessment*, Energy Commission Staff Report, CEC-600-2005-026-REV, September 2005.

8.4.1. Natural Gas Demand

Revisions to the preliminary reference case after the July 14 hearing resulted in some changes to natural gas demand in California. Total natural gas demand in California was projected to grow at a rate of 0.7 percent per year, from about 6.2 billion cfd in 2006 to 6.6 billion cfd in 2016 in the reference case.[256] With the changes made in response to comments received at the October 7 hearing, the growth rate dropped marginally from 0.7 percent to 0.6 percent. Strong growth in the residential and commercial sectors will be offset by declining industrial gas demand and slower growth in gas consumption by power generators than has been observed in recent years. Overall, the natural gas demand growth in the state is expected to be lower than the demand growth in the rest of the nation.

8.4.2. Natural Gas Supply

The September assessment addressed gas supplies available to North American markets generally, (increasing from approximately 80 billion cfd in 2006 to slightly more than 94 billion cfd in 2016.[257] The report included an assessment of natural gas supplies that California receives from various basins in the North American continent including the Western Canadian Sedimentary basin (principally, the province of Alberta, Canada), Rocky Mountain basins, and the Southwestern basins. By 2016, Southwest supplies continue to be the larger resources, satisfying 49 percent of California's market. Canadian and Rocky Mountain basins shares drop slightly to about 15 and 19 percent, respectively. California production, which has been declining over the past four years is seen as maintaining its market share at about 13 percent by 2016. LNG's share from the new Baja California projects in the state's total consumption will amount to about 4 percent by 2016. The report also included an assumption that the LNG portion of North American natural gas supply would increase by 16.4 percent during the forecast period.[258]

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[256] *Ibid.*

[257] *Ibid.*

[258] *Id*. at p. 27.

Since 2001, natural gas supplies in the North American continent have been observed to follow a different trend than during the previous decade. Even though the number of drilling rigs has kept pace with price and demand, total quantity of gas produced has been shy of meeting the demanded quantities. Hence the lower 48 states have had to increasingly rely either on Canadian imports or on LNG from a variety of foreign sources. Canadian use of natural gas also has grown, and basins in the Canadian producing provinces are facing similar difficulties as their US counterparts; it is anticipated in the long run that the production in Canada is not going to be sufficient to meet both Canada's own domestic needs and its export requirements to the US. This will likely lead to an increased reliance on and need to bring in natural gas as LNG from other available foreign sources.

Changes to assumptions after the October 7 hearing focused on transportation costs and hence did not significantly affect the production trends. The final reference case also shows supply trends as discussed above.

8.4.3. Natural Gas Prices

Since the energy crisis of 2001, natural gas prices that were anticipated to revert to the trends of the previous 10 to 15 years have instead consistently remained high. Events related to weather, global crude oil markets, and a decreasing rate in finding new natural gas supplies have continued to put pressure on natural gas prices across the nation. Notable recent events affecting natural gas production are the hurricanes impacting the Gulf of Mexico production. Generally, when industries have been impacted by hurricanes, they have recovered and begun normal operations within one to three months. However, this season the repeated and harsh impacts of two major hurricanes have crippled the natural gas and oil markets, with these effects lasting possibly for more than six months. These trends will place an upward pressure on natural gas prices. It is the industry's anticipation that the prices may not back down from the high levels we see today for a significant period of time.

Changes to the reference case suggested at the October 7 hearing did not change the Lower 48 annual average wellhead prices in any significant way.

The Committee received comments from several parties at the October 7 hearing on natural gas price forecasting issues. Many of these concerns can be summarized in the comments from Dr. Richard Ferguson, representing the Center for Energy Efficiency and Renewable Technologies. Dr. Ferguson's comments highlighted the growing difficulties in comparing the staff's forecast, or any other forecast, with natural gas market prices. It is clear that today's market prices are substantially higher than the staff's forecasted prices. The Committee identified this issue early in the 2005 Energy Report process and directed staff to hold a workshop on the models that provide the foundation for its forecasts. The comments the Committee received at that December 14, 2004 workshop demonstrated that the Energy Commission staff was using one of several currently available models and that its NARG-MB model was as good as any other model for its intended uses. As a result of that workshop, the Committee directed staff to continue its work with the NARG-MB model.

However, that workshop and the comments by Dr. Ferguson and others highlight a growing concern that confronts all parties in the U.S. who need to develop some long term-outlook on natural gas prices. The staff's model is based on the market fundamentals that normally drive the supply-demand balance in a well functioning market, and there is a long history of this and similar models providing reasonably accurate forecasts. However, in the past five years a number of factors have begun to drive prices away from a fundamental forecast of future prices. The Energy Commission takes note of not only the hurricanes mentioned above and their potential lasting effects, but also the price manipulation that has been documented in the Enron scandals and the misreporting of the natural gas price indices. These types of events cannot be forecast in advance with any accuracy, but they do have a real effect on market prices. Dr. Ferguson noted that without such advance knowledge, a fundamentals forecast will likely underrepresent future market prices.

While the Energy Commission shares concerns about the dilemma that Dr. Ferguson and others raised in this area, we note that many other parties continue to use fundamental forecasts in much the same way the Energy Commission staff does. The Energy Commission also notes that some parties provided comments that the Energy Commission's price forecast is too low, while others criticized it as too high. Unfortunately, no one provided a method of forecasting long term natural gas prices that was more robust and transparent than the staff's method. Therefore, the Energy Commission will adopt the staff's forecast for the 2005 Energy Report with the caveat that it should be augmented for its first two years by NYMEX prices. We also direct staff to further investigate alternative forecasting methods that can supplement the staff's current forecast and provide the 2007 Energy Report Committee with recommendations on how to better manage price forecast risks.

9. Transmission Project Recommendations

9.1. Procedural History

In 2002 and 2003, the Legislature added new electricity resource and transmission planning responsibilities to the Energy Commission's *Energy Report* process. In 2002 the Legislature also assigned new responsibilities to the CPUC concerning IOU procurement. More recently, the CA ISO has new management and in recognition of the seriousness of the state's growing transmission problems, is proposing to revamp its transmission and grid planning processes. These agencies must work hand-in-hand with the Legislature to produce a proactive and forward-looking transmission planning and permitting process for California.

Senate Bill 1565 (SB 1565, Bowen, Chapter 692, Statutes of 2004) added Public Resources Code Section 25324:

> The [Energy Commission], in consultation with the Public Utilities Commission, the California Independent System Operator, transmission owners, users, and consumers, shall adopt a strategic plan for the state's electric transmission grid using existing resources. The strategic plan shall identify and recommend actions required to implement investments needed to ensure reliability, relieve congestion, and meet future growth in load and generation, including, but not limited to, renewable resources, energy efficiency, and other demand reduction measures. The plan shall be included in the integrated energy policy report adopted on November 1, 2005, pursuant to subdivision (a) of Section 25302.

To meet this directive, as well as to receive input on critical transmission-related issues for inclusion in the *2005 Energy Report*, the Committee held multiple workshops. Committee workshops that focused on operational issues associated with integrating renewables were conducted on February 3 and May 10, 2005; the April 11, 2005 workshop focused on geothermal issues; and the May 9, 2005 workshop focused on renewable resource potential in California and interstate renewable resources. In addition, the May 19, 2005 Committee workshop focused on corridor planning and strategic transmission planning issues.

The *Transmission Staff Report*,[259] published on July 20, 2005, was the culmination of staff's compilation of information from these Energy Report Committee workshops, as well as the LSE transmission plans filed in response to the *Forms and Instructions for the Electricity Resources and Bulk Transmission Data Submittal*[260]. The *Transmission Staff Report* represents a comprehensive assessment of the status of transmission planning and permitting; transmission system problems and project updates; long-term corridor needs; and transmission issues associated with renewables integration; based on the Committee workshop record. The report also documents the Energy Commission staff's efforts to identify and evaluate the actions and strategies necessary to develop the foundation for the state's first *Strategic Transmission Investment Plan* (*Strategic Plan*).

The *Transmission Staff Report* focused on five areas:

- Transmission policy status (Chapter 2).
- Transmission problems and project update (Chapter 3).
- Transmission corridor planning and development (Chapter 4).
- The impact of transmission on renewable development (Chapter 5).
- Transmission policy options (Chapter 6).

A Committee hearing on Strategic Transmission Planning Issues and the *Transmission Staff Report* was held on July 28, 2005 to seek public comment on issues relating to the *Transmission Staff Report*, the strategic transmission planning process, and to review new contractor work completed after publication of the *Transmission Staff Report*. Interested parties were encouraged to present their views either in advance of the hearing, orally at the hearing, or in writing after the hearing. Reply comments were requested by August 4, 2005. Hearing transcripts were posted on the Energy Commission website on August 4, 2005.[261] Final contractor reports, presentation slides, and written comments are available online.

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[259] California Energy Commission, *Upgrading California's Electric Transmission System: Issues and Action for 2005 and Beyond*, July 2005. CEC 700-2005-018.

[260] California Energy Commission, *Forms and Instructions for the Electricity Resources and Bulk Transmission Data Submittal*, January 2005. CEC 100-2005-002-CMF.

[261] Transcripts: July 28, 2005 Re: Strategic Transmission Planning Issues and Transmission Staff Report Hearing. Docket No. 04-IEP-01F.

The notice for the hearing was posted July 14, 2005. The agenda, presentations and roundtable discussion questions were posted July 27, 2005 on the Energy Commission website. The hearing was conducted in coordination with the ACR issued by CPUC President Peevey in Rulemaking 04-04-003 on March 14, 2005. The ACR noted that the Integrated Energy Policy Report Committee would conduct public proceedings, including any hearings necessary pursuant to Public Utilities Code (PUC) section 1822, in its consideration of information used to determine the likely range of the specific needs of statewide load serving entities. Consistent with this requirement, the notice offered parties the opportunity to cross examine on issues relating to strategic transmission planning and on the *Transmission Staff Report*. Both of these topics support the creation of the state's first *Strategic Transmission Investment Plan* as required by Public Resources Code section 25324. No parties requested the opportunity to cross examine on these topics.

The following parties provided technical information or comments relevant to the hearing issues: Lawrence Berkeley National Laboratory (LBNL)/Consortium for Electric Reliability Technology Solutions (CERTS); Navigant Consulting; Pinnacle Consulting LLC; the Energy Commission; SDG&E; Imperial Irrigation District (IID); SCE; Los Angeles Department of Water and Power (LADWP); PG&E; TURN, Flynn RCI, and the CA ISO.

The discussion below summarizes staff's review of transmission projects and the comments of the various parties relating to these projects, focusing on the four projects the Energy Commission is recommending in the *Strategic Transmission Investment Plan* and the *Energy Report*.

9.2. Evaluation of Transmission Projects

The July 28, 2005 hearing included a request for feedback on the *Transmission Staff Report*. Staff posed the following questions to solicit comments on the report:

- Did the staff accurately capture parties' input?
- Are there other relevant points?
- Did staff draw appropriate conclusions?
- Did staff identify appropriate policy options?

Also at that hearing, staff introduced the PRC section 25324 directive and suggested the following criteria for including specific transmission projects in the Strategic Plan:

- The project could be on line by 2010.
- The project is in need of siting approval.
- The project meets the PRC Section 25324 guidelines.
- The project is consistent with 2003 and 2004 Energy Report recommendations.

Based on these criteria, the staff proposed nine projects for consideration in the Strategic Plan, using the 21 projects in Chapter 3 and Appendix F of the *Transmission Staff Report* as the starting point.[262] The following nine projects passed the first two screening criteria noted above of being able to be on line by 2010 and being in need of siting approval:

- Trans-Bay DC Cable Project (project #3[263])
- Metcalf-Moss Landing 230 kV Reinforcement (project #4)
- San Diego 500 kV Project (project #7)
- Lake Elsinore Advanced Pumped Storage (LEAPS) Project (project #8)
- South of Lugo Congestion Management (project #11)
- Path 26 Upgrades (project #12)
- Palo Verde-Devers No. 2 (project #15)
- Tehachapi Segment #1 and #2 (parts of project #16)
- Imperial Valley Transmission Upgrades (project #17)

The 12 projects which did not pass the first two screening criteria are noted below, along with staff's reasoning:

- Jefferson-Martin 230 kV Line (project #1) [CPCN granted in August 2004]
- San Francisco/Peninsula Long-term (2011+) Upgrades (project #2) [beyond 2010]
- Greater Fresno Area Projects (project #5) [beyond 2010]
- Sacramento Area Voltage Support Project (project #6) [Received Final Environmental Impact Statement and Record of Decision in January 2004]
- Otay Mesa Power Plant Transmission Project (project #9) [CPCN granted in June 2005]
- Miguel-Mission No. 2 230 kV Project (project #10) [CPCN granted in July 2004]
- Blythe Area Transmission Proposals (project #13) [both the Blythe II Power Plant Project and the Blythe Energy project Transmission Line are currently in the Energy Commission's Application For Certification process; therefore it is

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[262] California Energy Commission, Staff PowerPoint Presentation entitled "Upgrading California's Electric Transmission System: Issues and Actions for 2005 and Beyond," slide no. 14, posted July 28, 2005, [http://www.energy.ca.gov/2005_energypolicy/documents/2005-07-28_hearing/presentations/2005-07-28_GRAU_JUDY.PDF].

[263] Project numbering is consistent with the conventions used in Chapter 3 and Appendix F of the *Transmission Staff Report*.

procedurally inappropriate for the Energy Commission to comment on these projects at this time]

- Short-term STEP Upgrades (project #14) [CA ISO approval received in June 2004]
- Frontier Project (project #18) [conceptual project beyond 2010]
- Northern Lights Transmission Project (project #19) [conceptual project beyond 2010]
- Southwest Intertie Project (project #20) [out of state project for which most of the permitting has been completed]
- East of River 9000+ Project (project #21) [out of state project for which most of the permitting has been completed]

The July 28, 2005 hearing included a request for feedback on the development of the state's first *Strategic Transmission Investment Plan*. Staff posed the following questions:

- Do the projects presented in Chapter 3 and Appendix F of the Transmission Staff Report provide an appropriate foundation from which to develop the Strategic Plan?
- Which of the projects in Chapter 3 and Appendix F should be considered for inclusion in the Strategic Plan, and why?
- Are there other projects that should be considered?

SDG&E noted that transmission must be built in order to relieve congestion, noting that the next major transmission line will be needed around the year 2010.[264] Even with the addition of new generation plants coming on line in 2006 and 2008, the San Diego region does not have sufficient local generation to satisfy peak load requirements.[265] As a result, SDG&E must look at another transmission line into the area, and it is likely that the next 500 kV line, needed for reliability, will be from the east.[266] However, extensive land ownership east of San Diego includes Indian reservations, military bases, national forests, and other public lands that further complicate permitting, making it imperative that SDG&E have the ability to cross state or federal land in order to bring new transmission into San Diego.[267]

[264] Avery, July 28 TR at 90.

[265] *Id.* at 88.

[266] *Id.* at 88 to 92.

[267] *Id.* at 93.

In addition, SDG&E noted the need for a transmission link to the north at some point in time. Such a line could provide benefits to the state more so than to San Diego.[268] A link to the north could provide a conduit for economical generation from Arizona as well as for renewables from the Imperial Valley region.[269] SDG&E noted that proponents of the Lake Elsinore Advanced Pumped Storage (LEAPS) Project, which consists of both pumped hydro storage as well as transmission facilities, approached SDG&E several years ago with a proposal to connect it to SCE territory.[270] At the time, SDG&E did not believe the project was either economically or technically feasible, especially given the significant amount of federal land it must traverse and the fact that SDG&E has to pursue other alternatives before it can pursue federal land. Legislation that would provide access through the federal land would help the situation, but there are topographic and climate factors that present challenges.[271]

IID noted that the Transmission Staff Report accurately captured the Southern California transmission system and upgrade plans.[272] It noted that its transmission access is very limited and will not meet its future needs.[273] IID noted that its service area has some of the best geothermal resources in the state, as well as the potential for other green resources. IID believes that its philosophy of actively engaging its neighbors in planning joint transmission projects is essential for a robust transmission system.[274]

LADWP noted its commitment to remaining involved in the Tehachapi and Salton Sea area transmission planning groups.[275] Its Owens Gorge 230 kV line runs very near the Tehachapi area. LADWP believes the line will serve quite a lot of its renewable

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268 *Id.* at 94.

269 *Id.* at 94 to 97.

270 *Id.* at 98.

271 *Id.* at 98 to 99.

272 Barbera, July 28 TR at 102

273 *Id.* at 102 to 103.

274 *Id.* at 103 to 105.

275 Howard, July 28 TR at 161

generation requirements going forward: the existing line can carry 450 MW, and 160 MW of that is available for a potential tie-in to renewable resources there.[276]

PG&E offered some clarifications and updates to transmission projects in its service area. It noted that the Jefferson-Martin 230 kV line (project #1 in the Transmission Staff Report) is making good progress and is on track to be operational in the first half of 2006, at which point the Hunters Point Power Plant can be shut down. Project #2 (San Francisco/Peninsula Long-Term [2011+] Upgrades) and Project #3 (Trans-Bay DC Cable Project) could be the same project, depending on cost and need: the stakeholders and the CA ISO are still evaluating alternatives. The Henrietta-Gregg reconductoring projects, which is part of the Greater Fresno Area Projects (project #5), has recently received CPUC approval and PG&E plans to be in construction in 2006. PG&E supports the RPS target and schedule for the Tehachapi Area Renewable Interconnection (project #16), and it will work to make sure that the most cost-efficient solution is there to support the statewide goal. PG&E is still working on studies to determine if an interconnection from Tehachapi north to the PG&E network is needed. The identified problem is north of PG&E's Midway Substation, as Path 15 would reach its limit in the south to north direction before Path 26 would. The recent Path 26 upgrade to 4,000 MW (project #12) is only in the north to south direction.[277]

The following parties submitted written comments after the hearing: the League of California Cities/California State Association of Counties/Regional Council of Rural Counties, the California Department of Water Resources State Water Project, LADWP, and Vulcan Power Company[278]. With respect to the issue of which specific transmission projects should be included in the Strategic Plan, only LADWP and Vulcan Power Company provided comments. LADWP notes that SCE's economic analysis of Palo Verde-Devers No. 2 (PVD2) focuses on the increased revenue to SCE from existing

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[276] *Id.* at 161 to 162.

[277] Thomas, July 28 TR at 182-184.

[278] Reports, the hearing transcript, presentations and comments relating to this hearing are available on the Energy Commission's website at: [http://www.energy.ca.gov/2005_energypolicy/documents/index.html#072805].

See also the 2005 Energy Report Docket Log for Docket no. 04-IEP-1F at [http://www.energy.ca.gov/dockets/04-IEP-1F.html].

transmission contracts (ETCs) and the increased revenue to the CA ISO by wheeling through or out of the CA ISO grid. LADWP states that increased revenue for both SCE and the CA ISO at the expense of ETCs and wheel-throughs does not necessarily achieve the objectives of least cost, market efficiency, and resource flexibility; cost savings for one group at the expense of another should not be the goal of an overarching transmission plan.

Vulcan Power Company believes that the *Transmission Staff Report* focused too narrowly on the geothermal potential in the Imperial Valley without mentioning potential transmission upgrades that would benefit geothermal development outside the Imperial Valley, such as Northern California and across the border in Oregon and Nevada. Vulcan noted that it has submitted prior testimony in which it made recommendations for cost-effective transmission projects that could undergo expedited permitting processes because they involve upgrades to existing facilities and do not require the construction of additional transmission lines. Three of the most cost-effective recommendations include upgrades to the North of Cottonwood facilities, North of Round Mountain facilities, and North of Lugo facilities.

The *Draft Strategic Plan* was published on September 9, 2005.[279] The record of the *Draft Strategic Plan* incorporates all information, comments, filings, staff reports, consultant reports, and studies contained in the record of the *2003 Energy Report*, the *2004 Energy Report Update*, and the *2005 Energy Report*. This information is available on the Energy Commission's website:
[http://www.energy.ca.gov/2005_energypolicy/index.html].

Chapter 4 of the *Draft Strategic Plan* describes the transmission project investments for consideration. It first discusses the evaluation criteria used to screen the projects. Based on the record developed for the Transmission Staff Report and the July 28 hearing, seven projects were deemed the appropriate starting point.[280] The *Draft Strategic Plan* summarizes the conclusions reached for these projects.

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[279] California Energy Commission, *Strategic Transmission Investment Plan*, September 2005. CEC 100-2005-006CTD.

[280] The *Draft Strategic Plan* notes that seven projects passed the screening criteria (p. 62). Figure 4 on page 63 shows the seven projects. The seven projects in Figure 4 differ from the nine projects described at the July 28 Hearing in the following areas:

Footnote continued on next page

SDG&E Sunrise Powerlink 500 kV Project
(Project 1, *Draft Strategic Plan*, p. 65)

The proposed 500 kV Sunrise Powerlink Project would provide significant near-term system reliability benefits to California, reduce system congestion and resultant congestion costs, and provide an interconnection to renewable resources located in the Imperial Valley and lower-cost out-of-state generation. In addition, the proposed project would strengthen the CA ISO grid by providing a 500 kV interconnection between the SDG&E and SCE service territories. Further, without the proposed project SDG&E is likely to be unable to meet the state's RPS goals, ensure system reliability, or reduce RMR and congestion costs. Therefore, the Energy Commission believes the proposed project offers significant benefits and recommends that the project be moved forward expeditiously so that the residents of San Diego and all of California can begin realizing these benefits by 2010.

LEAPS 500 kV Transmission Project
(Project 2, *Draft Strategic Plan*, pp. 67-68)

The LEAPS transmission project would deliver pumped storage hydro power to the grid, reduce congestion and improve reliability in the San Diego area. The transmission component of LEAPS could supplant the northern interconnection of the Sunrise Powerlink 500 kV project, thereby assisting SDG&E in meeting resource and planning objectives for reliability, as well as meeting RPS goals. This would require coordination between the project sponsors and SDG&E. Furthermore, the transmission component of LEAPS could strengthen the regional transmission system. However, the Commission questions the need for both this project and the Sunrise Powerlink 500 kV project, which would provide similar benefits to the region in the near-term.

The proposed LEAPS project has unresolved environmental and cost effectiveness concerns, including:

- The San Diego 500 kV Project (referred to as project #7 in the Transmission Staff Report) has been renamed by SDG&E as the Sunrise Powerlink 500 KV Project.
- The Tehachapi Area Transmission Projects and Path 26 Upgrades (referred to as project #16 and #12, respectively, in the Transmission Staff Report) have been combined into one project with two parts (6a and 6b) in the *Draft Strategic Plan*.
- The Metcalf-Moss Landing 230 kV Reinforcement Project (project #4 in the *Transmission Staff Report*) has been removed from consideration because it is a reconductoring rather than a new line and its permitting requirements are uncertain at this time.

- ♦ Questions as to whether the proposed transmission component of LEAPS would complement or conflict with 500kV transmission projects under consideration by SDG&E.
- ♦ Economic studies have not been completed.
- ♦ The proposed transmission component of LEAPS would travel through the Cleveland National Forest and a large portion would cross other public lands. Therefore, the project would be subject to the requirements of the U.S. Forest Service (USFS), the Environmental Protection Agency (EPA), and the Bureau of Land Management (BLM).

The transmission component of LEAPS may offer substantial benefits to California and is worthy of further monitoring and future consideration. However, due to the lack of sufficient substantiation of near-term benefits, the project does not warrant recommendations for action at this time. To warrant future consideration in the 2007 *Energy Report* cycle, additional documentation of benefits is necessary.

Imperial Valley Transmission Upgrades Project
(Project 3, *Draft Strategic Plan*, p. 70)

The proposed Imperial Valley Transmission Upgrade Project would provide access to valuable renewable resources needed to meet future load growth, support California's RPS goals, and provide significant near-term system reliability benefits to California. Therefore, the Energy Commission believes the proposed project offers significant benefits and recommends that the project be moved forward expeditiously.

South of Lugo Vincent-Mira Loma 500 kV Project
(Project 4, *Draft Strategic Plan*, p. 71)

The proposed project is currently in the planning stage and neither project costs nor significant issues associated with the project have been identified. In addition, the proposed project would require CA ISO Board of Governors approval and a CPCN by the CPUC. However, any planning and permitting delays could mean that the Vincent to Mira Loma 500 kV line would not be operational in time to prevent violation of reliability standards south of Lugo starting in 2009 or 2010.

The proposed Vincent-Mira Loma 500 kV Project may offer substantial benefits to California and is worthy of further monitoring and future consideration. However, due to the lack of specific project details and studies, the project does not warrant recommendations for action at this time. To warrant future consideration in the 2007 *Energy Report* cycle, additional project documentation of benefits is necessary.

Palo Verde-Devers No. 2 500 kV Project
(Project 5, *Draft Strategic Plan*, p. 76)

> The proposed PVD2 Project would provide significant near-term benefits by reducing congestion on lines connecting California and Arizona and providing access to lower cost out-of-state generation to meet California's growing electricity needs. The proposed project would also provide strategic benefits to California ratepayers, including valuable insurance against abnormal system conditions and power outages, increased operating flexibility for California grid operators, reduced market power for generators, and reduced need for other infrastructure in California. Therefore, the Energy Commission believes the proposed project offers significant benefits and recommends that the project be moved forward expeditiously so that California can begin realizing these benefits by 2010.

Tehachapi Area/Path 26 Transmission Projects
(Project 6, *Draft Strategic Plan*, p. 81)

> The conceptual Tehachapi Transmission Plan would increase access to over 4,500 MW of renewable resources needed to serve California's growing electricity needs. The latter phases of the plan would add a northern Tehachapi connection to the PG&E network that could also reduce congestion on Path 26. The Energy Commission supports the conceptual Tehachapi Transmission Plan developed by the TSG [Tehachapi Collaborative Study Group] because it could provide access to 4,500 MW of renewable generation and will assist California utilities in meeting RPS goals by 2010. The Energy Commission believes the Antelope Transmission Project proposed by SCE is crucial to the development of wind resources in the Tehachapi region and will offer significant benefits to California. Therefore, the Commission recommends the project be moved forward expeditiously so that California can begin realizing benefits by 2010."

Trans-Bay DC Cable
(Project 7, *Draft Strategic Plan*, p. 82)

> Since this project is not under the jurisdiction of the CPUC, TBC [Trans Bay Cable LLC] requested approval of their finance proposal from FERC. FERC approved the TBC Operating Memorandum for the $300 million project on July 22, 2005. The CA ISO has recently completed its technical review of the project for the San Francisco Peninsula study group and recommended the Trans-Bay Cable as its preferred alternative for meeting the long-term reliability needs of the San Francisco Peninsula. While TBC supports the completion of the project in 2009, the CA ISO study indicates economic benefits from the project would not be realized until 2012. The Trans-Bay DC Cable still requires CA ISO Board of Governors approval and will be presented for consideration on September 8, 2005. With approval, the project could be operational by 2009. Pending CA ISO board approval, the Energy Commission recommends monitoring and future consideration of the project.

In summary, the *Draft Strategic Plan* recommends four projects as important components: the SDG&E Sunrise Powerlink Project, the Imperial Valley Transmission Upgrades Project, the Palo Verde-Devers No. 2 Project, and the Antelope Transmission Project (part of the Tehachapi Area Transmission Projects.) A fifth project, the Trans-Bay DC Cable, received conditional support pending the outcome of CA ISO Board of Governors action.

A Committee hearing was held on September 23, 2005 to seek public comment on the *Draft Strategic Plan* as part of the 2005 Energy Report proceeding. Interested parties were encouraged to present their views either in advance of the hearing, orally at the hearing, or in writing after the hearing. Reply comments were requested by October 14, 2005. Hearing transcripts were posted on the Energy Commission website on October 3, 2005.[281] Presentations and the transcript of the hearing are available online at [http://www.energy.ca.gov/2005_energypolicy/documents/index.html#092305].

The notice for the hearing on the *Draft Strategic Plan* was posted on the Energy Commission website on September 9, 2005. The agenda was posted on September 19, 2005, while staff presentations were posted on September 22, 2005. The hearing was conducted in coordination with the ACR issued by CPUC President Peevey in Rulemaking 04-04-003 on March 14, 2005. The ACR noted that the Integrated Energy Policy Report Committee would conduct public proceedings, including any hearings necessary pursuant to Public Utilities Code (PUC) section 1822, in its consideration of information used to determine the likely range of the specific needs of statewide load serving entities. Consistent with this requirement, the notice offered parties the opportunity to cross examine on issues relating to the *Draft Strategic Plan*. No parties requested the opportunity to cross examine on this topic.

At the September 23, 2005 Hearing, Commissioner Geesman noted that the CA ISO Board approved the Trans-Bay Cable project shortly after the *Draft Strategic Plan* was published, and asked Energy Commission staff if this would "elevate this project into that group of four priority projects that we are recommending go forward."[282] Staff

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[281] Transcripts: September 23, 2005 Re: Committee Draft 2005 Strategic Transmission Investment Plan Hearing. Docket No. 04-IEP-01K.

[282] Geesman, September 23 TR at 16.

agreed and asked parties to provide comments on this addition either at the hearing or in writing.[283]

SDG&E agreed with the *Draft Strategic Plan's* support for the Sunrise Powerlink Project. It noted that it expects to file its application for a CPCN for the need for the project "within the next couple of months."[284] It plans to file its environmental assessment at the end of the second calendar quarter of 2006.[285] SDG&E advocates working collaboratively with the state's consultants to prepare that assessment jointly, as a means to save both time and money, with the objective of receiving a need determination by the third calendar quarter of 2006 and a CPCN by the end of 2006.[286] In addition, SDG&E plans to bring together state, federal, and local agencies, business and consumer groups, environmental communities, and "traditional opponents" as another means to expedite the project.[287]

SDG&E noted that it has signed contracts for renewable resources at the eastern end of the line in the Imperial Valley which could total up to 900 MW.[288] Furthermore, SDG&E stated that "With what we have under contract, we could be close to 16 percent renewables before or by 2010, and what we are still trying to negotiate could easily exceed that 20 percent target by 2010. The one thing that is going to hamper us is the inability to get it to use without transmission."[289] The project would also mitigate "a large percentage" of forecasted RMR costs.[290]

ORA noted that it believes that it is the only party that submitted testimony on the Tehachapi Phase 1 (Antelope Transmission Project) application for a CPCN. ORA recommended support for the line. ORA notes that "We did raise a couple of issues regarding the rate making treatment Edison has proposed, and we are working with

[283] Grau, September 23 TR at 16.

[284] Avery, September 23 TR at 17-18.

[285] *Id.* at 18.

[286] *Id.* at 18 to 21.

[287] *Id.* at 22.

[288] *Id.* at 23.

[289] Avery, September 23 TR at 26.

[290] *Id.* at 25-26.

Edison about settling those issues to avoid the need for hearings, just to be able to expedite the whole process."[291]

Commissioner Geesman noted that the *Draft Strategic Plan* speaks in terms of approving that project as required by law within its twelve month time period. Given ORA's expectation that that process will be expedited, Commissioner Geesman asked if his understanding is correct that the publication date for the final CEQA documents has slipped to March 2006. The ORA representative agreed to check on that.[292]

Commissioner Geesman asked PG&E to provide written comments on PG&E's going-forward position on the Trans-Bay Cable Project and its willingness to facilitate the completion of the project. PG&E noted that "We will do our part to whatever needs to be interconnected, so, we will see how they proceed, and let's hope that San Francisco gets the reliability it needs through all the projects that are out there."[293]

9.3. Final Project Recommendations

Consistent with the above discussion, the transmission projects described below will provide significant near-term benefits to California through improvements to system reliability, reduced congestion, and/or interconnection to renewable resources. The Energy Commission recommends investment in the following projects.

9.3.1. PVD2 500 kV Project

The proposed PVD2 500 kV Project would provide significant near-term benefits by reducing congestion on lines connecting California and Arizona and providing access to lower-cost out-of-state generation. The proposed project would also provide strategic benefits to California ratepayers, including valuable insurance against abnormal system conditions and power outages. It would increase operating flexibility for California grid operators, reduce market power for generators, and reduce the need for additional infrastructure in California. The PVD2 Project is therefore a major component of California's Strategic Plan. The Energy Commission strongly believes that

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[291] Kinosian, September 23 TR at 32.

[292] *Id.* at 38-39.

[293] Guliasi, September 23 TR at 56-58.

the proposed project offers significant benefits and recommends that the project be moved forward expeditiously so that California can begin realizing these benefits by 2010.

9.3.2. Sunrise Powerlink 500 kV Project

The proposed 500 kV Sunrise Powerlink Project would provide significant near-term system reliability benefits to California, reduce system congestion and resultant congestion costs, and provide an interconnection to renewable resources located in the Imperial Valley. The proposed project would also strengthen the CA ISO grid by providing a 500 kV interconnection between the SDG&E and SCE service territories. Further, without the proposed project SDG&E is not likely to meet the state's RPS goals, ensure system reliability, or reduce RMR and congestion costs. The Energy Commission strongly believes that the proposed project offers significant benefits and recommends that the project be moved forward expeditiously so that the residents of San Diego and all of California can begin realizing these benefits by 2010.

9.3.3. Tehachapi Transmission Plan, Phase One: Antelope Transmission Project

The Energy Commission strongly believes that the Antelope Transmission Project, proposed by SCE, is crucial to the development of wind resources in the Tehachapi region and will offer significant benefits to California. As such, the proposed project is considered a major component of California's Strategic Plan. The Energy Commission therefore recommends the project be moved forward expeditiously so that California can begin realizing benefits by 2010.

9.3.4. Imperial Valley Transmission Upgrade Project

The proposed Imperial Valley Transmission Upgrade Project would provide access to valuable renewable resources needed to meet future load growth, support California's RPS goals, and provide significant near-term system reliability benefits to California. Therefore, the Energy Commission believes the proposed project offers significant benefits and recommends that the project be moved forward expeditiously.

9.3.5. Trans-Bay DC Cable Project

Although the Trans-Bay DC Cable Project is not needed for reliability purposes until after 2011, the CA ISO has approved the project for early operation in 2009, consistent with TBC's plans. The Energy Commission agrees with CA ISO's assessment that the advanced in-service date provides insurance benefits that outweigh the net cost to CA ISO ratepayers.[294] Therefore, the Energy Commission recommends the Trans-Bay DC Cable Project be moved forward expeditiously so that the San Francisco peninsula and the CA ISO control area can realize these benefits.

9.4. CPUC Actions to Implement Investments

The CPUC should take action to ensure that the CPCN permitting processes for the DPV2 and Tehachapi Phase I projects are effective and completed in the 12 months required by law. The CPUC should take action to ensure that long-term strategic benefits are fully addressed in CPUC permitting assessments of project benefits for transmission projects deemed vital to the state in the Energy Commission's Strategic Plan.

The CPUC should assign great weight in its permitting process to the project need assessments submitted by the CA ISO.

Although the CPUC's permitting responsibilities in the Imperial Valley Transmission Upgrades and Trans-Bay Cable projects are limited[295], the CPUC should

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[294] "This Project is needed for reliability and is being recommended to mitigate violation of reliability planning standards beginning in 2012, but is being recommended for early operation. The Project, as currently structured, is planned to be in-service by 2009…[T]he ISO performed technical and economic analyses to assess the reliability benefits and the cost to the ISO ratepayers for advancing the in-service date by three years to 2009. ISO's technical analysis concluded that installation of this project in 2009 would significantly improve reliability of the San Francisco Peninsula electrical system… This Project, with a 2009 in-service date, will significantly reduce expected Locational Capacity Requirements and the need for Special Protection Schemes that are currently in place to shed firm load for critical double contingency disturbances for San Francisco Peninsula. Further, ISO's economic analysis concluded that while the Project does have identified benefits, the present value of the revenue requirements of the benefits and costs over the three-year advancement results in a net cost to the ISO ratepayers of $26 million. This "net cost" is viewed as an assurance cost against intangible benefits such as immediate increased reliability to the San Francisco Peninsula Area, unforeseen load forecast errors and consideration of unknowns such as project siting, schedule, cost risks, and economic benefits." (Letter, Gary DeShazo, CA ISO Director of Regional Transmission to ISO Board of Governors, "Approval of the Trans Bay HVDC Cable Project, September 2, 2005.)

[295] The PG&E Pittsburg and Potrero Substation modifications required for the Trans-Bay Cable Project are likely exempt from the CPCN and Permit To Construct (PTC) requirements pursuant to General Order (GO) 131-D Section III. Similarly, any SDG&E and/or SCE substation modifications required for the Imperial Valley Transmission Upgrade Project will likely be exempt from GO 131-D Section III. However, Public Utilities Code Section 762 may require the

Footnote continued on next page

ensure that it fulfills its Public Utilities Code Section 762 responsibilities in a timely manner.

10. Public Comment

Interested parties are invited to comment on this *Committee Draft Transmittal Report*. A hearing on the draft report will be held on November 4, 2005, at the Energy Commission in Sacramento. We encourage parties to submit written comments in advance of the hearing. Please include the docket number "04 IEP 1K Committee Draft Document Hearings" in the subject line or initial paragraph of your comments. Those submitting written comments by electronic mail should provide the comments in either Microsoft Word format or Portable Document Format (PDF), but parties must also submit one paper copy to the Energy Commission's Dockets Unit. Email comments should be sent to: docket@energy.state.ca.us. Please include your name or your organization's name in the name of the file. Those submitting written comments only by hard copy must provide an original plus 18 paper copies to the Energy Commission's Dockets Unit. Those submitting comments after the hearing should submit them to dockets no later than November 8, 2005.

Please send or deliver materials to:

California Energy Commission Dockets Unit
Attn: Docket No. 04 IEP 1K
1516 Ninth Street, MS-4
Sacramento, CA 95814-5512

Alternatively, participants may provide an original and 18 copies at the beginning of the hearings. All written materials relating to this hearing will be filed with the Dockets Unit and will become part of the public record in this proceeding.

The final version of this report will include a section responding to the comments received.

CPUC to make and serve an order directing that such improvements be made after consideration of such factors as community values, recreational and park areas, historical and aesthetic values, and influence on the environment.

10.1. Opportunity for Cross Examination

In its March 14, 2005 Order re: Coordination with the CPUC's 2006 Procurement Proceeding, the Committee stated that the 2005 Energy Report Proceedings would be conducted in coordination with the ACR issued by CPUC President Peevey in Rulemaking 04-04-003 on March 14, 2005. The ACR noted that the Integrated Policy Report Committee would conduct public proceedings, including any hearings necessary pursuant to Public Utilities Code section 1822, in its consideration of information used to determine the likely range of statewide and LSE-specific need.

Public Utilities Code section 1822 establishes a requirement that the CPUC provide access to computer models that are the basis of testimony or an exhibit in a hearing. An exception is provided for those computer models that are the subject of Energy Commission hearings at which testimony is offered subject to cross-examination. Therefore, if any participant in the Energy Report process would like the opportunity to conduct cross-examination on the use of models as they relate to matters being transmitted to the CPUC for their use in future proceedings, he or she must so notify the Committee no later than November 1, 2005. The notice must include an identification of the specific topic(s) of the cross-examination and an estimate of the time required to conduct the cross-examination. If any participant files such a notice, the Committee will conduct a pre-hearing conference at the beginning of the hearing to establish applicable procedures.

10.2. Specific Issues

This draft report includes a number of key determinations that the Committee specifically invites parties to comment.

10.2.1. Renewable Amounts in the Preferred Resources

Among the resource plan scenarios the Energy Commission directed the IOUs to file was one reflecting the accelerated targets recommended by the Energy Commission in the *2004 Energy Report Update*, which aim at PG&E and SDG&E achieving 33 percent renewables by 2020, and SCE, which has the greatest renewable potential in its service territory, achieving 35 percent by 2020.[296] The Energy Commission is including in the

[296] *2004 Energy Report Update*, pp. 37-39.

preferred resource category the amount of renewable energy and capacity identified by the IOUs as necessary to meet the accelerated targets. The Energy Commission recognizes that these scenarios were not based on the revised staff demand forecasts and that the trajectory of that level of future purchases would not be 33 percent of demand in 2020 when using the revised staff forecast. Nonetheless, the primary purpose of identifying a preferred level of renewable resources on the need tables is to avoid procuring so much in additional undesignated resources that renewable purchases to meet future targets are precluded. Therefore, the Energy Commission considers the generic renewable resources identified by the IOUs in their accelerated renewables cases to be a useful benchmark. The Energy Commission invites comments on this approach and any recommendations for alternate approaches to determining the amount of preferred renewables to include in the need tables.

10.2.2. Existing Demand Response

The Energy Commission did not collect specific information on existing demand response programs other than the interruptible programs as part of the 2005 Energy Report proceeding. Therefore, no estimate of these existing non-interruptible programs is available for inclusion in the existing resource portions of the range of need tables. For this reason, the Energy Commission is including the full target of five percent of distribution service area load within the additional preferred resources category on the range of need tables. The Energy Commission invites comments on this approach and any recommendations for alternate approaches to determining the amount of preferred renewables to include in the need tables.

10.2.3. Distribution Service Area Capacity Tables

Due to confidentiality constraints, the only capacity data from the resource plans that have been published have been those found in the public tables initially filed by the IOUs and the tables in the *Aggregated Table Report* that were aggregated to the planning area level. The POUs within the PG&E and SCE planning areas did not request confidentiality for their resource plan data, so there are not any constraints on publishing the POU data.[297] The Energy Commission proposes to publish that data in

[297] The SDG&E planning area does not include any POUs.

the final *Transmittal Report*, and to create new range of need tables that subtracts the public values for the POUs from the planning area values previously published to generate distribution service area tables for the three IOUs. The Energy Commission invites comments from the IOUs and other parties on this plan.

10.2.4. Use of NYMEX for Near-term Natural Gas Prices

The Energy Commission plans to adopt the staff's natural gas price forecast for the *2005 Energy Report* with the caveat that it should be augmented for its first two years by NYMEX prices. The Energy Commission invites comment on this plan, including specific recommendations for how it should be implemented or alternative approaches.

Appendix A: Aging Power Plant Study Group

Planning Area	Plant	Unit	Capacity (MW)	Average Generation 2002-2004 (GWH)
PG&E	Contra Costa	6	340	359
		7	340	777
	Humboldt Bay	1	52	174
		2	53	160
	Hunters Point	4	163	471
	Morro Bay	1	163	11
		2	163	33
		3	338	294
		4	338	420
	Moss Landing	6	739	1,074
		7	739	1,083
	Pittsburg	5	325	675
		6	325	503
		7	720	1,504
	Potrero	3	207	765
PG&E Total			**5,005**	**8,303**
SDG&E	Encina	1	107	146
		2	104	186
		3	110	263
		4	293	1,022
		5	315	1,158
	South Bay	1	147	491
		2	150	534
		3	171	454
		4	222	129
SDG&E Total			**1,619**	**4,383**

Appendix A: Aging Power Plant Study Group (continued)

Planning Area	Plant	Unit	Capacity (MW)	Average Generation 2002-2004 (GWH)
SCE	Alamitos	1	175	122
		2	175	134
		3	320	946
		4	320	636
		5	480	1,124
		6	480	621
	Coolwater	1	65	37
		2	81	50
		3	241	620
		4	241	525
	El Segundo	3	335	681
		4	335	729
	Etiwanda	3	320	253
		4	320	185
	Huntington Beach	1	215	689
		2	215	723
	Long Beach	8	303	-
		9	227	-
	Mandalay	1	215	367
		2	215	445
	Ormond Beach	1	750	1,101
		2	750	1,101
	Redondo Beach	5	175	83
		6	175	34
		7	480	741
		8	480	604
SCE Total			**8,088**	**12,551**
Grand Total			**14,712**	**25,237**

Appendix B: Tables Showing Range of Need

Table B-1
Annual Aggregated Energy Resource Accounting Table
PG&E Low Demand Case

	2009	2010	2011	2012	2013	2014	2015	2016
ENERGY DEMAND (GWh)								
Net Energy for Bundled Customer Load (low case)	84,825	86,071	87,456	88,652	89,961	90,972	91,998	93,008
Firm Sales Obligations	413	413	413	413	413	413	413	413
TOTAL ENERGY REQUIREMENT	**85,238**	**86,484**	**87,869**	**89,065**	**90,374**	**91,385**	**92,411**	**93,421**
EXISTING & PLANNED RESOURCES								
Utility-Controlled Physical Resources								
Nuclear	15,573	17,546	17,597	16,797	17,584	17,551	16,746	17,624
Fossil (**)	177	178	171	173	171	174	174	180
Total Hydro Energy Supply	15,983	15,290	15,023	15,061	14,174	13,534	13,347	12,471
Total Utility-Controlled Physical Resources	**31,733**	**33,014**	**32,790**	**32,030**	**31,929**	**31,259**	**30,267**	**30,275**
Existing and Planned Contractual Resources								
Total Energy Supply from DWR Contracts	21,203	3,079	2,482	1,190	0	0	0	0
Total Energy Supply from QF Contracts	19,727	19,939	19,873	19,769	19,708	19,592	19,463	19,387
Total Existing & Planned Renewable Contracts	519	526	528	528	527	300	66	31
Total Energy Supply from Other Bilateral Contracts	3,585	3,670	2,076	1,063	516	518	429	413
Total Contractual Resources	**45,034**	**27,214**	**24,959**	**22,550**	**20,750**	**20,410**	**19,958**	**19,831**
TOTAL EXISTING & PLANNED ENERGY RESOURCES	**76,766**	**60,228**	**57,749**	**54,580**	**52,679**	**51,669**	**50,225**	**50,106**
SUPPLY/DEMAND BALANCE	**8,472**	**26,256**	**30,120**	**34,485**	**37,695**	**39,717**	**42,186**	**43,315**
Aging Plant Replacement	**1,875**	**3,749**	**5,624**	**7,498**	**7,498**	**7,498**	**7,498**	**7,498**
TOTAL NEED, INCLUDING AGING PLANT REPLACEMENT	**10,346**	**30,005**	**35,744**	**41,983**	**45,193**	**47,215**	**49,684**	**50,813**
ADDITIONAL PREFERRED RESOURCES								
Uncommitted Energy Efficiency	1,057	2,119	3,123	4,204	5,380	6,650	7,903	9,136
Renewables	5,423	6,481	6,961	7,890	8,259	9,267	10,513	11,306
Distributed Generation/ CHP	to be developed in 2006 by Energy Commission and CPUC							
TOTAL ADDITIONAL PREFERRED RESOURCES (*)	**6,480**	**8,600**	**10,084**	**12,094**	**13,639**	**15,917**	**18,416**	**20,442**
ADDITIONAL NON-DESIGNATED NEED (*)	**3,866**	**21,405**	**25,660**	**29,889**	**31,554**	**31,298**	**31,268**	**30,371**

* - The total preferred resources will increase and the open source need will decrease when DG/CHP targets are established in 2006.
** - In its reference case, PG&E did not include any energy values for the Humboldt Bay replacement project, though it included 150 MW of capacity. The Energy Commission is including the fossil resource energy values that PG&E filed with its preferred, accelerated renewables, and core/non-core cases.

Table B-2
Annual Aggregated Energy Resource Accounting Table
PG&E Base Demand Case

	2009	2010	2011	2012	2013	2014	2015	2016
ENERGY DEMAND (GWh)								
Net Energy for Bundled Customer Load (base case)	85,182	86,451	87,855	89,069	90,395	91,426	92,471	93,504
Firm Sales Obligations	413	413	413	413	413	413	413	413
TOTAL ENERGY REQUIREMENT	**85,595**	**86,864**	**88,268**	**89,482**	**90,808**	**91,839**	**92,884**	**93,917**
EXISTING & PLANNED RESOURCES								
Utility-Controlled Physical Resources								
Nuclear	15,573	17,546	17,597	16,797	17,584	17,551	16,746	17,624
Fossil (**)	177	178	171	173	171	174	174	180
Total Hydro Energy Supply	15,983	15,290	15,023	15,061	14,174	13,534	13,347	12,471
Total Utility-Controlled Physical Resources	**31,733**	**33,014**	**32,790**	**32,030**	**31,929**	**31,259**	**30,267**	**30,275**
Existing and Planned Contractual Resources								
Total Energy Supply from DWR Contracts	21,203	3,079	2,482	1,190	0	0	0	0
Total Energy Supply from QF Contracts	19,727	19,939	19,873	19,769	19,708	19,592	19,463	19,387
Total Existing & Planned Renewable Contracts	519	526	528	528	527	300	66	31
Total Energy Supply from Other Bilateral Contracts	3,585	3,670	2,076	1,063	516	518	429	413
Total Contractual Resources	**45,034**	**27,214**	**24,959**	**22,550**	**20,750**	**20,410**	**19,958**	**19,831**
TOTAL EXISTING & PLANNED ENERGY RESOURCES	**76,766**	**60,228**	**57,749**	**54,580**	**52,679**	**51,669**	**50,225**	**50,106**
SUPPLY/DEMAND BALANCE	**8,829**	**26,636**	**30,519**	**34,902**	**38,129**	**40,171**	**42,659**	**43,810**
Aging Plant Replacement	**1,875**	**3,749**	**5,624**	**7,498**	**7,498**	**7,498**	**7,498**	**7,498**
TOTAL NEED, INCLUDING AGING PLANT REPLACEMENT	**10,703**	**30,385**	**36,142**	**42,400**	**45,627**	**47,669**	**50,157**	**51,308**
ADDITIONAL PREFERRED RESOURCES								
Uncommitted Energy Efficiency	1,057	2,119	3,123	4,204	5,380	6,650	7,903	9,136
Renewables	5,423	6,481	6,961	7,890	8,259	9,267	10,513	11,306
Distributed Generation/ CHP	to be developed in 2006 by Energy Commission and CPUC							
TOTAL ADDITIONAL PREFERRED RESOURCES (*)	**6,480**	**8,600**	**10,084**	**12,094**	**13,639**	**15,917**	**18,416**	**20,442**
ADDITIONAL NON-DESIGNATED NEED (*)	**4,223**	**21,785**	**26,058**	**30,306**	**31,988**	**31,752**	**31,741**	**30,866**

* - The total preferred resources will increase and the open source need will decrease when DG/CHP targets are established in 2006.
** - In its reference case, PG&E did not include any energy values for the Humboldt Bay replacement project, though it included 150 MW of capacity. The Energy Commission is including the fossil resource energy values that PG&E filed with its preferred, accelerated renewables, and core/non-core cases.

Table B-3
Annual Aggregated Energy Resource Accounting Table
PG&E High Demand Case

	2009	2010	2011	2012	2013	2014	2015	2016
ENERGY DEMAND (GWh)								
Net Energy for Bundled Customer Load (high case)	86,621	88,237	90,023	91,600	93,374	94,894	96,452	97,959
Firm Sales Obligations	413	413	413	413	413	413	413	413
TOTAL ENERGY REQUIREMENT	**87,034**	**88,650**	**90,436**	**92,013**	**93,787**	**95,307**	**96,865**	**98,372**
EXISTING & PLANNED RESOURCES								
Utility-Controlled Physical Resources								
Nuclear	15,573	17,546	17,597	16,797	17,584	17,551	16,746	17,624
Fossil (**)	177	178	171	173	171	174	174	180
Total Hydro Energy Supply	15,983	15,290	15,023	15,061	14,174	13,534	13,347	12,471
Total Utility-Controlled Physical Resources	**31,733**	**33,014**	**32,790**	**32,030**	**31,929**	**31,259**	**30,267**	**30,275**
Existing and Planned Contractual Resources								
Total Energy Supply from DWR Contracts	21,203	3,079	2,482	1,190	0	0	0	0
Total Energy Supply from QF Contracts	19,727	19,939	19,873	19,769	19,708	19,592	19,463	19,387
Total Existing & Planned Renewable Contracts	519	526	528	528	527	300	66	31
Total Energy Supply from Other Bilateral Contracts	3,585	3,670	2,076	1,063	516	518	429	413
Total Contractual Resources	**45,034**	**27,214**	**24,959**	**22,550**	**20,750**	**20,410**	**19,958**	**19,831**
TOTAL EXISTING & PLANNED ENERGY RESOURCES	**76,766**	**60,228**	**57,749**	**54,580**	**52,679**	**51,669**	**50,225**	**50,106**
SUPPLY/DEMAND BALANCE	**10,268**	**28,422**	**32,688**	**37,434**	**41,108**	**43,639**	**46,640**	**48,266**
Aging Plant Replacement	**1,875**	**3,749**	**5,624**	**7,498**	**7,498**	**7,498**	**7,498**	**7,498**
TOTAL NEED, INCLUDING AGING PLANT REPLACEMENT	**12,142**	**32,171**	**38,311**	**44,932**	**48,606**	**51,137**	**54,138**	**55,764**
ADDITIONAL PREFERRED RESOURCES								
Uncommitted Energy Efficiency	1,057	2,119	3,123	4,204	5,380	6,650	7,903	9,136
Renewables	5,423	6,481	6,961	7,890	8,259	9,267	10,513	11,306
Distributed Generation/ CHP	to be developed in 2006 by Energy Commission and CPUC							
TOTAL ADDITIONAL PREFERRED RESOURCES (*)	**6,480**	**8,600**	**10,084**	**12,094**	**13,639**	**15,917**	**18,416**	**20,442**
ADDITIONAL NON-DESIGNATED NEED (*)	**5,662**	**23,571**	**28,227**	**32,838**	**34,967**	**35,220**	**35,722**	**35,322**

* - The total preferred resources will increase and the open source need will decrease when DG/CHP targets are established in 2006.
* - In its reference case, PG&E did not include any energy values for the Humboldt Bay replacement project, though it included 150 MW of capacity. The Energy Commission is including the fossil resource energy values that PG&E filed with its preferred, accelerated renewables, and core/non-core cases.

Table B-4
Annual Aggregated Capacity Resource Accounting Table
PG&E Low Demand Case

	2009	2010	2011	2012	2013	2014	2015	2016
PEAK DEMAND (MW)								
Peak Service Area Demand (low case) (*)	19,311	19,583	19,893	20,156	20,448	20,676	20,923	21,169
Peak Bundled Customer Demand (low case)	17,959	18,221	18,520	18,773	19,055	19,276	19,518	19,760
Reserve Margin (at 15%)	2,897	2,937	2,984	3,023	3,067	3,101	3,139	3,175
Firm Sales Obligations	0	0	0	0	0	0	0	0
Firm Peak Requirement	**20,856**	**21,158**	**21,504**	**21,796**	**22,122**	**22,377**	**22,657**	**22,935**
EXISTING & PLANNED CAPACITY								
Utility-Controlled Physical Resources								
Nuclear	2,214	2,214	2,214	2,214	2,214	2,214	2,214	2,214
Fossil	150	150	150	150	150	150	150	150
Total Dependable Hydro Capacity	4,734	4,734	4,734	4,734	4,734	4,667	4,667	4,667
Total Utility-Controlled Physical Resources	**7,098**	**7,098**	**7,098**	**7,098**	**7,098**	**7,031**	**7,031**	**7,031**
Contractual Resources								
DWR Contracts	4,392	2,392	1,597	263	90	90	0	0
QF Contracts	2,559	2,536	2,532	2,517	2,508	2,495	2,478	2,472
Renewable Contracts (**)	169	170	171	172	174	96	97	96
Other Bilateral Contracts (**)	1,522	1,536	1,525	1,538	873	888	880	800
Total Contractual Resources	**8,642**	**6,634**	**5,825**	**4,491**	**3,645**	**3,569**	**3,455**	**3,367**
TOTAL EXISTING & PLANNED CAPACITY	**15,740**	**13,732**	**12,922**	**11,588**	**10,743**	**10,599**	**10,486**	**10,398**
Existing Interruptible/ Emergency Programs	**374**	**374**	**374**	**374**	**374**	**374**	**374**	**374**
SUPPLY/DEMAND BALANCE	**4,742**	**7,053**	**8,208**	**9,834**	**11,005**	**11,404**	**11,797**	**12,163**
Aging Plant Replacement	**1,184**	**2,369**	**3,553**	**4,737**	**4,737**	**4,737**	**4,737**	**4,737**
TOTAL NEED, INCLUDING AGING PLANT REPLACEMENT	**5,926**	**9,421**	**11,760**	**14,571**	**15,742**	**16,141**	**16,534**	**16,900**
ADDITIONAL PREFERRED RESOURCES								
Uncommitted Energy Efficiency	226	463	692	952	1,295	1,535	1,777	2,069
Uncommitted Dispatchable Demand Response	966	979	995	1,008	1,022	1,034	1,046	1,058
Renewables	679	790	916	1,017	1,115	1,245	1,412	1,505
Distributed Generation/ CHP	to be developed in 2006 by Energy Commission and CPUC							
TOTAL ADDITIONAL PREFERRED RESOURCES (***)	**1,871**	**2,232**	**2,603**	**2,977**	**3,432**	**3,814**	**4,235**	**4,632**
ADDITIONAL NON-DESIGNATED NEED (***)	**4,055**	**7,189**	**9,158**	**11,594**	**12,310**	**12,327**	**12,299**	**12,268**

* - Peak service area demand is used for calculation of the uncommitteed dispatchable demand reponse targets.

** - Planning area data are presented here because the IOU-specific data are confidential.

*** - Total preferred resource will increase and the open source need will decrease when DG/CHP targets are established in 2006.

Table B-5
Annual Aggregated Capacity Resource Accounting Table
PG&E Base Demand Case

	2009	2010	2011	2012	2013	2014	2015	2016
PEAK DEMAND (MW)								
Peak Service Area Demand (base case) (*)	19,397	19,675	19,989	20,256	20,552	20,785	21,037	21,288
Peak Bundled Customer Demand (base case)	18,044	18,311	18,614	18,872	19,158	19,383	19,631	19,877
Reserve Margin (at 15%)	2,910	2,951	2,998	3,038	3,083	3,118	3,156	3,193
Firm Sales Obligations	0	0	0	0	0	0	0	0
Firm Peak Requirement	**20,954**	**21,262**	**21,612**	**21,910**	**22,241**	**22,501**	**22,787**	**23,070**
EXISTING & PLANNED CAPACITY								
Utility-Controlled Physical Resources								
Nuclear	2,214	2,214	2,214	2,214	2,214	2,214	2,214	2,214
Fossil	150	150	150	150	150	150	150	150
Total Dependable Hydro Capacity	4,734	4,734	4,734	4,734	4,734	4,667	4,667	4,667
Total Utility-Controlled Physical Resources	**7,098**	**7,098**	**7,098**	**7,098**	**7,098**	**7,031**	**7,031**	**7,031**
Contractual Resources								
DWR Contracts	4,392	2,392	1,597	263	90	90	0	0
QF Contracts	2,559	2,536	2,532	2,517	2,508	2,495	2,478	2,472
Renewable Contracts (**)	169	170	171	172	174	96	97	96
Other Bilateral Contracts (**)	1,522	1,536	1,525	1,538	873	888	880	800
Total Contractual Resources	**8,642**	**6,634**	**5,825**	**4,491**	**3,645**	**3,569**	**3,455**	**3,367**
TOTAL EXISTING & PLANNED CAPACITY	**15,740**	**13,732**	**12,922**	**11,588**	**10,743**	**10,599**	**10,486**	**10,398**
Existing Interruptible/ Emergency Programs	**374**	**374**	**374**	**374**	**374**	**374**	**374**	**374**
SUPPLY/DEMAND BALANCE	**4,839**	**7,156**	**8,316**	**9,948**	**11,124**	**11,527**	**11,927**	**12,298**
Aging Plant Replacement	**1,184**	**2,369**	**3,553**	**4,737**	**4,737**	**4,737**	**4,737**	**4,737**
TOTAL NEED, INCLUDING AGING PLANT REPLACEMENT	**6,024**	**9,525**	**11,869**	**14,685**	**15,861**	**16,264**	**16,664**	**17,035**
ADDITIONAL PREFERRED RESOURCES								
Uncommitted Energy Efficiency	226	463	692	952	1,295	1,535	1,777	2,069
Uncommitted Dispatchable Demand Response	970	984	999	1,013	1,028	1,039	1,052	1,064
Renewables	679	790	916	1,017	1,115	1,245	1,412	1,505
Distributed Generation/ CHP	to be developed in 2006 by Energy Commission and CPUC							
TOTAL ADDITIONAL PREFERRED RESOURCES (***)	**1,875**	**2,237**	**2,607**	**2,982**	**3,438**	**3,819**	**4,241**	**4,638**
ADDITIONAL NON-DESIGNATED NEED (***)	**4,149**	**7,288**	**9,261**	**11,703**	**12,423**	**12,445**	**12,423**	**12,397**

* - Peak service area demand is used for calculation of the uncommitteed dispatchable demand reponse targets.
** - Planning area data are presented here because the IOU-specific data are confidential.
*** - Total preferred resource will increase and the open source need will decrease when DG/CHP targets are established in 2006.

Table B-6
Annual Aggregated Capacity Resource Accounting Table
PG&E High Demand Case

	2009	2010	2011	2012	2013	2014	2015	2016
PEAK DEMAND (MW)								
Peak Service Area Demand (high case) (*)	19,709	20,060	20,455	20,800	21,189	21,521	21,878	22,227
Peak Bundled Customer Demand (high case)	18,344	18,682	19,062	19,394	19,768	20,088	20,434	20,755
Reserve Margin (at 15%)	2,956	3,009	3,068	3,120	3,178	3,228	3,282	3,334
Firm Sales Obligations	0	0	0	0	0	0	0	0
Firm Peak Requirement	**21,300**	**21,691**	**22,130**	**22,514**	**22,946**	**23,316**	**23,716**	**24,089**
EXISTING & PLANNED CAPACITY								
Utility-Controlled Physical Resources								
Nuclear	2,214	2,214	2,214	2,214	2,214	2,214	2,214	2,214
Fossil	150	150	150	150	150	150	150	150
Total Dependable Hydro Capacity	4,734	4,734	4,734	4,734	4,734	4,667	4,667	4,667
Total Utility-Controlled Physical Resources	**7,098**	**7,098**	**7,098**	**7,098**	**7,098**	**7,031**	**7,031**	**7,031**
Contractual Resources								
DWR Contracts	4,392	2,392	1,597	263	90	90	0	0
QF Contracts	2,559	2,536	2,532	2,517	2,508	2,495	2,478	2,472
Renewable Contracts (**)	169	170	171	172	174	96	97	96
Other Bilateral Contracts (**)	1,522	1,536	1,525	1,538	873	888	880	800
Total Contractual Resources	**8,642**	**6,634**	**5,825**	**4,491**	**3,645**	**3,569**	**3,455**	**3,367**
TOTAL EXISTING & PLANNED CAPACITY	**15,740**	**13,732**	**12,922**	**11,588**	**10,743**	**10,599**	**10,486**	**10,398**
Existing Interruptible/ Emergency Programs	**374**	**374**	**374**	**374**	**374**	**374**	**374**	**374**
SUPPLY/DEMAND BALANCE	**5,186**	**7,585**	**8,834**	**10,552**	**11,829**	**12,343**	**12,856**	**13,317**
Aging Plant Replacement	**1,184**	**2,369**	**3,553**	**4,737**	**4,737**	**4,737**	**4,737**	**4,737**
TOTAL NEED, INCLUDING AGING PLANT REPLACEMENT	**6,370**	**9,954**	**12,387**	**15,289**	**16,566**	**17,080**	**17,593**	**18,054**
ADDITIONAL PREFERRED RESOURCES								
Uncommitted Energy Efficiency	226	463	692	952	1,295	1,535	1,777	2,069
Uncommitted Dispatchable Demand Response	985	1,003	1,023	1,040	1,059	1,076	1,094	1,111
Renewables	679	790	916	1,017	1,115	1,245	1,412	1,505
Distributed Generation/ CHP	to be developed in 2006 by Energy Commission and CPUC							
TOTAL ADDITIONAL PREFERRED RESOURCES (***)	**1,890**	**2,256**	**2,631**	**3,009**	**3,469**	**3,856**	**4,283**	**4,685**
ADDITIONAL NON-DESIGNATED NEED (***)	**4,480**	**7,698**	**9,756**	**12,280**	**13,097**	**13,224**	**13,310**	**13,369**

* - Peak service area demand is used for calculation of the uncommitteed dispatchable demand reponse targets.
** - Planning area data are presented here because the IOU-specific data are confidential.
*** - Total preferred resource will increase and the open source need will decrease when DG/CHP targets are established in 2006.

Table B-7
Annual Aggregated Energy Resource Accounting Table
SCE Low Demand Case

	2009	2010	2011	2012	2013	2014	2015	2016
ENERGY DEMAND (GWh)								
Net Energy for Bundled Customer Load (low case)	84,003	85,067	86,141	87,319	88,365	89,444	90,516	91,423
Firm Sales Obligations	2,144	2,144	2,144	2,151	2,144	2,144	2,144	2,151
TOTAL ENERGY REQUIREMENT	**86,147**	**87,211**	**88,286**	**89,470**	**90,509**	**91,589**	**92,661**	**93,574**
EXISTING & PLANNED RESOURCES								
Utility-Controlled Physical Resources								
Nuclear	9,671	9,095	10,063	10,610	10,280	9,534	9,859	9,414
Fossil	16,234	15,862	17,596	17,469	17,520	17,509	17,280	17,293
Total Hydro Energy Supply	4,679	4,675	4,705	4,597	4,591	4,602	4,625	4,642
Total Utility-Controlled Physical Resources	**30,584**	**29,632**	**32,364**	**32,675**	**32,391**	**31,645**	**31,764**	**31,349**
Existing and Planned Contractual Resources								
Total Energy Supply from DWR Contracts	19,946	19,946	16,755	0	0	0	0	0
Total Energy Supply from QF Contracts	25,033	24,993	24,956	24,987	24,892	24,864	24,838	24,879
Total Existing & Planned Renewable Contracts	2,841	2,841	2,841	2,848	2,841	2,841	2,841	2,848
Total Energy Supply from Other Bilateral Contracts	6,352	6,419	1,754	1,406	1,406	1,388	1,383	1,383
Total Contractual Resources	**54,172**	**54,198**	**46,306**	**29,241**	**29,139**	**29,093**	**29,062**	**29,110**
TOTAL EXISTING & PLANNED ENERGY RESOURCES	**84,756**	**83,830**	**78,670**	**61,916**	**61,529**	**60,738**	**60,826**	**60,459**
SUPPLY/DEMAND BALANCE	**1,392**	**3,381**	**9,616**	**27,554**	**28,980**	**30,851**	**31,835**	**33,115**
Aging Plant Replacement	**3,138**	**6,276**	**9,413**	**12,551**	**12,551**	**12,551**	**12,551**	**12,551**
TOTAL NEED, INCLUDING AGING PLANT REPLACEMENT	**4,529**	**9,657**	**19,029**	**40,105**	**41,531**	**43,402**	**44,386**	**45,666**
ADDITIONAL PREFERRED RESOURCES								
Uncommitted Energy Efficiency	866	1,783	2,708	3,956	5,191	6,426	7,660	8,895
Renewables	4,630	5,613	6,401	7,042	8,774	9,054	10,158	11,257
Distributed Generation/ CHP	to be developed in 2006 by Energy Commission and CPUC							
TOTAL ADDITIONAL PREFERRED RESOURCES (*)	**5,496**	**7,396**	**9,109**	**10,998**	**13,965**	**15,480**	**17,818**	**20,152**
ADDITIONAL NON-DESIGNATED NEED (*)	**-967**	**2,261**	**9,920**	**29,107**	**27,566**	**27,922**	**26,568**	**25,514**

* - The total preferred resources will increase and the open source need will decrease when DG/CHP targets are established in 2006.

Table B-8
Annual Aggregated Energy Resource Accounting Table
SCE Base Demand Case

	2009	2010	2011	2012	2013	2014	2015	2016
ENERGY DEMAND (GWh)								
Net Energy for Bundled Customer Load (base case)	84,589	85,703	86,822	88,045	89,132	90,258	91,342	92,254
Firm Sales Obligations	2,144	2,144	2,144	2,151	2,144	2,144	2,144	2,151
TOTAL ENERGY REQUIREMENT	**86,733**	**87,847**	**88,967**	**90,196**	**91,276**	**92,403**	**93,486**	**94,405**
EXISTING & PLANNED RESOURCES								
Utility-Controlled Physical Resources								
Nuclear	9,671	9,095	10,063	10,610	10,280	9,534	9,859	9,414
Fossil	16,234	15,862	17,596	17,469	17,520	17,509	17,280	17,293
Total Hydro Energy Supply	4,679	4,675	4,705	4,597	4,591	4,602	4,625	4,642
Total Utility-Controlled Physical Resources	**30,584**	**29,632**	**32,364**	**32,675**	**32,391**	**31,645**	**31,764**	**31,349**
Existing and Planned Contractual Resources								
Total Energy Supply from DWR Contracts	19,946	19,946	16,755	0	0	0	0	0
Total Energy Supply from QF Contracts	25,033	24,993	24,956	24,987	24,892	24,864	24,838	24,879
Total Existing & Planned Renewable Contracts	2,841	2,841	2,841	2,848	2,841	2,841	2,841	2,848
Total Energy Supply from Other Bilateral Contracts	6,352	6,419	1,754	1,406	1,406	1,388	1,383	1,383
Total Contractual Resources	**54,172**	**54,198**	**46,306**	**29,241**	**29,139**	**29,093**	**29,062**	**29,110**
TOTAL EXISTING & PLANNED ENERGY RESOURCES	**84,756**	**83,830**	**78,670**	**61,916**	**61,529**	**60,738**	**60,826**	**60,459**
SUPPLY/DEMAND BALANCE	**1,978**	**4,018**	**10,297**	**28,280**	**29,747**	**31,665**	**32,660**	**33,946**
Aging Plant Replacement	**3,138**	**6,276**	**9,413**	**12,551**	**12,551**	**12,551**	**12,551**	**12,551**
TOTAL NEED, INCLUDING AGING PLANT REPLACEMENT	**5,115**	**10,293**	**19,710**	**40,831**	**42,298**	**44,216**	**45,211**	**46,497**
ADDITIONAL PREFERRED RESOURCES								
Uncommitted Energy Efficiency	866	1,783	2,708	3,956	5,191	6,426	7,660	8,895
Renewables	4,630	5,613	6,401	7,042	8,774	9,054	10,158	11,257
Distributed Generation/ CHP	to be developed in 2006 by Energy Commission and CPUC							
TOTAL ADDITIONAL PREFERRED RESOURCES (*)	**5,496**	**7,396**	**9,109**	**10,998**	**13,965**	**15,480**	**17,818**	**20,152**
ADDITIONAL NON-DESIGNATED NEED (*)	**-381**	**2,897**	**10,601**	**29,833**	**28,333**	**28,736**	**27,393**	**26,345**

* - The total preferred resources will increase and the open source need will decrease when DG/CHP targets are established in 2006.

Table B-9
Annual Aggregated Energy Resource Accounting Table
SCE High Demand Case

	2009	2010	2011	2012	2013	2014	2015	2016
ENERGY DEMAND (GWh)								
Net Energy for Bundled Customer Load (high case)	85,421	86,758	88,092	89,554	90,901	92,385	93,815	95,048
Firm Sales Obligations	2,144	2,144	2,144	2,151	2,144	2,144	2,144	2,151
TOTAL ENERGY REQUIREMENT	**87,566**	**88,902**	**90,237**	**91,705**	**93,046**	**94,530**	**95,959**	**97,199**
EXISTING & PLANNED RESOURCES								
Utility-Controlled Physical Resources								
Nuclear	9,671	9,095	10,063	10,610	10,280	9,534	9,859	9,414
Fossil	16,234	15,862	17,596	17,469	17,520	17,509	17,280	17,293
Total Hydro Energy Supply	4,679	4,675	4,705	4,597	4,591	4,602	4,625	4,642
Total Utility-Controlled Physical Resources	**30,584**	**29,632**	**32,364**	**32,675**	**32,391**	**31,645**	**31,764**	**31,349**
Existing and Planned Contractual Resources								
Total Energy Supply from DWR Contracts	19,946	19,946	16,755	0	0	0	0	0
Total Energy Supply from QF Contracts	25,033	24,993	24,956	24,987	24,892	24,864	24,838	24,879
Total Existing & Planned Renewable Contracts	2,841	2,841	2,841	2,848	2,841	2,841	2,841	2,848
Total Energy Supply from Other Bilateral Contracts	6,352	6,419	1,754	1,406	1,406	1,388	1,383	1,383
Total Contractual Resources	**54,172**	**54,198**	**46,306**	**29,241**	**29,139**	**29,093**	**29,062**	**29,110**
TOTAL EXISTING & PLANNED ENERGY RESOURCES	**84,756**	**83,830**	**78,670**	**61,916**	**61,529**	**60,738**	**60,826**	**60,459**
SUPPLY/DEMAND BALANCE	**2,810**	**5,072**	**11,567**	**29,789**	**31,517**	**33,792**	**35,133**	**36,739**
Aging Plant Replacement	**3,138**	**6,276**	**9,413**	**12,551**	**12,551**	**12,551**	**12,551**	**12,551**
TOTAL NEED, INCLUDING AGING PLANT REPLACEMENT	**5,948**	**11,348**	**20,980**	**42,340**	**44,068**	**46,343**	**47,684**	**49,290**
ADDITIONAL PREFERRED RESOURCES								
Uncommitted Energy Efficiency	866	1,783	2,708	3,956	5,191	6,426	7,660	8,895
Renewables	4,630	5,613	6,401	7,042	8,774	9,054	10,158	11,257
Distributed Generation/ CHP	to be developed in 2006 by Energy Commission and CPUC							
TOTAL ADDITIONAL PREFERRED RESOURCES (*)	**5,496**	**7,396**	**9,109**	**10,998**	**13,965**	**15,480**	**17,818**	**20,152**
ADDITIONAL NON-DESIGNATED NEED (*)	**452**	**3,952**	**11,871**	**31,342**	**30,103**	**30,863**	**29,866**	**29,138**

* - The total preferred resources will increase and the open source need will decrease when DG/CHP targets are established in 2006.

Table B-10
Annual Aggregated Capacity Resource Accounting Table
SCE Low Demand Case

	2009	2010	2011	2012	2013	2014	2015	2016
PEAK DEMAND (MW)								
Peak Service Area Demand (low case) (*)	21,168	21,441	21,714	22,009	22,275	22,555	22,834	23,077
Peak Bundled Customer Demand (low case)	19,171	19,434	19,697	19,981	20,237	20,504	20,773	21,009
Reserve Margin (at 15%)	3,175	3,216	3,257	3,301	3,341	3,383	3,425	3,462
Firm Sales Obligations	255	255	255	255	255	255	255	255
Firm Peak Requirement	**22,602**	**22,906**	**23,210**	**23,538**	**23,834**	**24,143**	**24,454**	**24,726**
EXISTING & PLANNED CAPACITY								
Utility-Controlled Physical Resources								
Nuclear	2,289	2,289	2,289	2,289	2,289	2,289	2,289	2,289
Fossil	1,648	1,645	1,643	1,641	1,638	1,637	1,637	1,637
Total Dependable Hydro Capacity	1,069	1,069	1,069	1,069	1,069	1,069	1,069	1,069
Total Utility-Controlled Physical Resources	**5,006**	**5,003**	**5,001**	**4,999**	**4,996**	**4,995**	**4,995**	**4,995**
Contractual Resources								
DWR Contracts	3,217	3,217	2,415	0	0	0	0	0
QF Contracts	3,211	3,211	3,211	3,211	3,211	3,211	3,211	3,211
Renewable Contracts (**)	405	412	415	417	425	428	436	444
Other Bilateral Contracts (**)	1,261	1,230	1,174	1,179	1,202	1,222	1,233	1,260
Total Contractual Resources	**8,095**	**8,070**	**7,216**	**4,807**	**4,839**	**4,861**	**4,880**	**4,915**
TOTAL EXISTING & PLANNED CAPACITY	**13,101**	**13,074**	**12,217**	**9,806**	**9,835**	**9,857**	**9,876**	**9,911**
Existing Interruptible/ Emergency Programs	**1,037**	**1,037**	**1,037**	**1,037**	**1,037**	**1,037**	**1,037**	**1,037**
SUPPLY/DEMAND BALANCE	**8,464**	**8,795**	**9,956**	**12,695**	**12,962**	**13,249**	**13,541**	**13,778**
Aging Plant Replacement	**2,022**	**4,044**	**6,066**	**8,088**	**8,088**	**8,088**	**8,088**	**8,088**
TOTAL NEED, INCLUDING AGING PLANT REPLACEMENT	**10,486**	**12,839**	**16,022**	**20,783**	**21,050**	**21,337**	**21,629**	**21,866**
ADDITIONAL PREFERRED RESOURCES								
Uncommitted Energy Efficiency	196	393	591	852	1,112	1,372	1,632	1,893
Uncommitted Dispatchable Demand Response	1,058	1,072	1,086	1,100	1,114	1,128	1,142	1,154
Renewables	962	1,183	1,293	1,375	1,621	1,656	1,912	2,048
Distributed Generation/ CHP	to be developed in 2006 by Energy Commission and CPUC							
TOTAL ADDITIONAL PREFERRED RESOURCES (***)	**2,216**	**2,648**	**2,970**	**3,327**	**3,847**	**4,156**	**4,686**	**5,095**
ADDITIONAL NON-DESIGNATED NEED (***)	**8,270**	**10,191**	**13,052**	**17,455**	**17,203**	**17,181**	**16,943**	**16,771**

* - Peak service area demand is used for calculation of the uncommitteed dispatchable demand reponse targets.
** - Planning area data are presented here because the IOU-specific data are confidential.
*** - Total preferred resource will increase and the open source need will decrease when DG/CHP targets are established in 2006.

Table B-11
Annual Aggregated Capacity Resource Accounting Table
SCE Base Demand Case

	2009	2010	2011	2012	2013	2014	2015	2016
PEAK DEMAND (MW)								
Peak Service Area Demand (base case) (*)	21,334	21,621	21,906	22,215	22,493	22,786	23,068	23,313
Peak Bundled Customer Demand (base case)	19,335	19,612	19,888	20,184	20,452	20,733	21,005	21,243
Reserve Margin (at 15%)	3,200	3,243	3,286	3,332	3,374	3,418	3,460	3,497
Firm Sales Obligations	255	255	255	255	255	255	255	255
Firm Peak Requirement	**22,790**	**23,111**	**23,429**	**23,772**	**24,081**	**24,406**	**24,721**	**24,995**
EXISTING & PLANNED CAPACITY								
Utility-Controlled Physical Resources								
Nuclear	2,289	2,289	2,289	2,289	2,289	2,289	2,289	2,289
Fossil	1,648	1,645	1,643	1,641	1,638	1,637	1,637	1,637
Total Dependable Hydro Capacity	1,069	1,069	1,069	1,069	1,069	1,069	1,069	1,069
Total Utility-Controlled Physical Resources	**5,006**	**5,003**	**5,001**	**4,999**	**4,996**	**4,995**	**4,995**	**4,995**
Contractual Resources								
DWR Contracts	3,217	3,217	2,415	0	0	0	0	0
QF Contracts	3,211	3,211	3,211	3,211	3,211	3,211	3,211	3,211
Renewable Contracts (**)	405	412	415	417	425	428	436	444
Other Bilateral Contracts (**)	1,261	1,230	1,174	1,179	1,202	1,222	1,233	1,260
Total Contractual Resources	**8,095**	**8,070**	**7,216**	**4,807**	**4,839**	**4,861**	**4,880**	**4,915**
TOTAL EXISTING & PLANNED CAPACITY	**13,101**	**13,074**	**12,217**	**9,806**	**9,835**	**9,857**	**9,876**	**9,911**
Existing Interruptible/ Emergency Programs	**1,037**	**1,037**	**1,037**	**1,037**	**1,037**	**1,037**	**1,037**	**1,037**
SUPPLY/DEMAND BALANCE	**8,653**	**9,000**	**10,176**	**12,929**	**13,209**	**13,513**	**13,808**	**14,048**
Aging Plant Replacement	**2,022**	**4,044**	**6,066**	**8,088**	**8,088**	**8,088**	**8,088**	**8,088**
TOTAL NEED, INCLUDING AGING PLANT REPLACEMENT	**10,675**	**13,044**	**16,242**	**21,017**	**21,297**	**21,601**	**21,896**	**22,136**
ADDITIONAL PREFERRED RESOURCES								
Uncommitted Energy Efficiency	196	393	591	852	1,112	1,372	1,632	1,893
Uncommitted Dispatchable Demand Response	1,067	1,081	1,095	1,111	1,125	1,139	1,153	1,166
Renewables	962	1,183	1,293	1,375	1,621	1,656	1,912	2,048
Distributed Generation/ CHP	to be developed in 2006 by Energy Commission and CPUC							
TOTAL ADDITIONAL PREFERRED RESOURCES (***)	**2,225**	**2,657**	**2,979**	**3,338**	**3,858**	**4,167**	**4,697**	**5,107**
ADDITIONAL NON-DESIGNATED NEED (***)	**8,450**	**10,387**	**13,262**	**17,679**	**17,440**	**17,433**	**17,199**	**17,029**

* - Peak service area demand is used for calculation of the uncommitteed dispatchable demand reponse targets.

** - Planning area data are presented here because the IOU-specific data are confidential.

*** - Total preferred resource will increase and the open source need will decrease when DG/CHP targets are established in 2006.

Table B-12
Annual Aggregated Capacity Resource Accounting Table
SCE High Demand Case

	2009	2010	2011	2012	2013	2014	2015	2016
PEAK DEMAND (MW)								
Peak Service Area Demand (high case) (*)	21,518	21,853	22,185	22,545	22,878	23,243	23,596	23,908
Peak Bundled Customer Demand (high case)	19,506	19,827	20,146	20,490	20,808	21,155	21,492	21,791
Reserve Margin (at 15%)	3,228	3,278	3,328	3,382	3,432	3,486	3,539	3,586
Firm Sales Obligations	255	255	255	255	255	255	255	255
Firm Peak Requirement	**22,989**	**23,360**	**23,729**	**24,127**	**24,495**	**24,897**	**25,287**	**25,633**
EXISTING & PLANNED CAPACITY								
Utility-Controlled Physical Resources								
Nuclear	2,289	2,289	2,289	2,289	2,289	2,289	2,289	2,289
Fossil	1,648	1,645	1,643	1,641	1,638	1,637	1,637	1,637
Total Dependable Hydro Capacity	1,069	1,069	1,069	1,069	1,069	1,069	1,069	1,069
Total Utility-Controlled Physical Resources	**5,006**	**5,003**	**5,001**	**4,999**	**4,996**	**4,995**	**4,995**	**4,995**
Contractual Resources								
DWR Contracts	3,217	3,217	2,415	0	0	0	0	0
QF Contracts	3,211	3,211	3,211	3,211	3,211	3,211	3,211	3,211
Renewable Contracts (**)	405	412	415	417	425	428	436	444
Other Bilateral Contracts (**)	1,261	1,230	1,174	1,179	1,202	1,222	1,233	1,260
Total Contractual Resources	**8,095**	**8,070**	**7,216**	**4,807**	**4,839**	**4,861**	**4,880**	**4,915**
TOTAL EXISTING & PLANNED CAPACITY	**13,101**	**13,074**	**12,217**	**9,806**	**9,835**	**9,857**	**9,876**	**9,911**
Existing Interruptible/ Emergency Programs	**1,037**	**1,037**	**1,037**	**1,037**	**1,037**	**1,037**	**1,037**	**1,037**
SUPPLY/DEMAND BALANCE	**8,852**	**9,249**	**10,475**	**13,284**	**13,623**	**14,003**	**14,374**	**14,685**
Aging Plant Replacement	**2,022**	**4,044**	**6,066**	**8,088**	**8,088**	**8,088**	**8,088**	**8,088**
TOTAL NEED, INCLUDING AGING PLANT REPLACEMENT	**10,874**	**13,293**	**16,541**	**21,372**	**21,711**	**22,091**	**22,462**	**22,773**
ADDITIONAL PREFERRED RESOURCES								
Uncommitted Energy Efficiency	196	393	591	852	1,112	1,372	1,632	1,893
Uncommitted Dispatchable Demand Response	1,076	1,093	1,109	1,127	1,144	1,162	1,180	1,195
Renewables	962	1,183	1,293	1,375	1,621	1,656	1,912	2,048
Distributed Generation/ CHP	to be developed in 2006 by Energy Commission and CPUC							
TOTAL ADDITIONAL PREFERRED RESOURCES (***)	**2,234**	**2,669**	**2,993**	**3,354**	**3,877**	**4,190**	**4,724**	**5,136**
ADDITIONAL NON-DESIGNATED NEED (***)	**8,640**	**10,625**	**13,548**	**18,018**	**17,834**	**17,901**	**17,738**	**17,637**

* - Peak service area demand is used for calculation of the uncommitteed dispatchable demand reponse targets.

** - Planning area data are presented here because the IOU-specific data are confidential.

*** - Total preferred resource will increase and the open source need will decrease when DG/CHP targets are established in 2006.

Table B-13
Annual Aggregated Energy Resource Accounting Table
SDG&E Low Demand Case

	2009	2010	2011	2012	2013	2014	2015	2016
ENERGY DEMAND (GWh)								
Net Energy for Bundled Customer Load (low case)	18,472	18,765	19,057	19,351	19,642	19,928	20,217	20,500
Firm Sales Obligations								
TOTAL ENERGY REQUIREMENT	**18,472**	**18,765**	**19,057**	**19,351**	**19,642**	**19,928**	**20,217**	**20,500**
EXISTING & PLANNED RESOURCES								
Utility-Controlled Physical Resources								
Nuclear	3,164	2,338	2,554	2,563	2,387	2,715	2,394	2,561
Fossil	4,003	3,956	3,869	3,931	3,962	3,993	4,016	4,087
Total Hydro Energy Supply	-17	-15	-15	-15	-16	-16	-15	-14
Total Utility-Controlled Physical Resources	**7,150**	**6,279**	**6,408**	**6,479**	**6,333**	**6,692**	**6,395**	**6,635**
Existing and Planned Contractual Resources								
Total Energy Supply from DWR Contracts	1,590	1,589	0	0	0	0	0	0
Total Energy Supply from QF Contracts	1,718	1,718	1,716	1,716	1,714	1,713	1,718	1,721
Total Existing & Planned Renewable Contracts	1,009	1,004	978	971	908	879	873	875
Total Energy Supply from Other Bilateral Contracts	5,167	4,638	4,185	3,008	2,207	1,457	1,375	1,664
Total Contractual Resources	**9,485**	**8,948**	**6,879**	**5,696**	**4,829**	**4,050**	**3,966**	**4,259**
TOTAL EXISTING & PLANNED ENERGY RESOURCES	**16,635**	**15,227**	**13,286**	**12,175**	**11,162**	**10,742**	**10,361**	**10,894**
SUPPLY/DEMAND BALANCE	**1,837**	**3,538**	**5,771**	**7,176**	**8,480**	**9,186**	**9,856**	**9,606**
Aging Plant Replacement	**1,096**	**2,192**	**3,287**	**4,383**	**4,383**	**4,383**	**4,383**	**4,383**
TOTAL NEED, INCLUDING AGING PLANT REPLACEMENT	**2,933**	**5,730**	**9,058**	**11,559**	**12,863**	**13,569**	**14,239**	**13,989**
ADDITIONAL PREFERRED RESOURCES								
Uncommitted Energy Efficiency	141	419	687	929	1,148	1,431	1,741	2,066
Renewables	574	2,453	2,710	2,920	3,236	3,672	4,075	4,460
Distributed Generation/ CHP	to be developed in 2006 by Energy Commission and CPUC							
TOTAL ADDITIONAL PREFERRED RESOURCES (*)	**715**	**2,872**	**3,397**	**3,849**	**4,384**	**5,103**	**5,816**	**6,526**
ADDITIONAL NON-DESIGNATED NEED (*)	**2,218**	**2,858**	**5,661**	**7,710**	**8,479**	**8,466**	**8,423**	**7,463**

* - The total preferred resources will increase and the open source need will decrease when DG/CHP targets are established in 2006.

Table B-14
Annual Aggregated Energy Resource Accounting Table
SDG&E Base Demand Case

	2009	2010	2011	2012	2013	2014	2015	2016
ENERGY DEMAND (GWh)								
Net Energy for Bundled Customer Load (base case)	18,627	18,930	19,228	19,529	19,825	20,117	20,400	20,679
Firm Sales Obligations								
TOTAL ENERGY REQUIREMENT	**18,627**	**18,930**	**19,228**	**19,529**	**19,825**	**20,117**	**20,400**	**20,679**
EXISTING & PLANNED RESOURCES								
Utility-Controlled Physical Resources								
Nuclear	3,164	2,338	2,554	2,563	2,387	2,715	2,394	2,561
Fossil	4,003	3,956	3,869	3,931	3,962	3,993	4,016	4,087
Total Hydro Energy Supply	-17	-15	-15	-15	-16	-16	-15	-14
Total Utility-Controlled Physical Resources	**7,150**	**6,279**	**6,408**	**6,479**	**6,333**	**6,692**	**6,395**	**6,635**
Existing and Planned Contractual Resources								
Total Energy Supply from DWR Contracts	1,590	1,589	0	0	0	0	0	0
Total Energy Supply from QF Contracts	1,718	1,718	1,716	1,716	1,714	1,713	1,718	1,721
Total Existing & Planned Renewable Contracts	1,009	1,004	978	971	908	879	873	875
Total Energy Supply from Other Bilateral Contracts	5,167	4,638	4,185	3,008	2,207	1,457	1,375	1,664
Total Contractual Resources	**9,485**	**8,948**	**6,879**	**5,696**	**4,829**	**4,050**	**3,966**	**4,259**
TOTAL EXISTING & PLANNED ENERGY RESOURCES	**16,635**	**15,227**	**13,286**	**12,175**	**11,162**	**10,742**	**10,361**	**10,894**
SUPPLY/DEMAND BALANCE	**1,993**	**3,702**	**5,942**	**7,354**	**8,663**	**9,375**	**10,039**	**9,785**
Aging Plant Replacement	**1,096**	**2,192**	**3,287**	**4,383**	**4,383**	**4,383**	**4,383**	**4,383**
TOTAL NEED, INCLUDING AGING PLANT REPLACEMENT	**3,088**	**5,894**	**9,229**	**11,737**	**13,046**	**13,758**	**14,422**	**14,168**
ADDITIONAL PREFERRED RESOURCES								
Uncommitted Energy Efficiency	141	419	687	929	1,148	1,431	1,741	2,066
Renewables	574	2,453	2,710	2,920	3,236	3,672	4,075	4,460
Distributed Generation/ CHP	to be developed in 2006 by Energy Commission and CPUC							
TOTAL ADDITIONAL PREFERRED RESOURCES (*)	**715**	**2,872**	**3,397**	**3,849**	**4,384**	**5,103**	**5,816**	**6,526**
ADDITIONAL NON-DESIGNATED NEED (*)	**2,373**	**3,022**	**5,832**	**7,888**	**8,662**	**8,655**	**8,606**	**7,642**

* - The total preferred resources will increase and the open source need will decrease when DG/CHP targets are established in 2006.

Table B-15
Annual Aggregated Energy Resource Accounting Table
SDG&E High Demand Case

	2009	2010	2011	2012	2013	2014	2015	2016
ENERGY DEMAND (GWh)								
Net Energy for Bundled Customer Load (high case)	18,792	19,135	19,476	19,822	20,167	20,513	20,849	21,185
Firm Sales Obligations								
TOTAL ENERGY REQUIREMENT	**18,792**	**19,135**	**19,476**	**19,822**	**20,167**	**20,513**	**20,849**	**21,185**
EXISTING & PLANNED RESOURCES								
Utility-Controlled Physical Resources								
Nuclear	3,164	2,338	2,554	2,563	2,387	2,715	2,394	2,561
Fossil	4,003	3,956	3,869	3,931	3,962	3,993	4,016	4,087
Total Hydro Energy Supply	-17	-15	-15	-15	-16	-16	-15	-14
Total Utility-Controlled Physical Resources	**7,150**	**6,279**	**6,408**	**6,479**	**6,333**	**6,692**	**6,395**	**6,635**
Existing and Planned Contractual Resources								
Total Energy Supply from DWR Contracts	1,590	1,589	0	0	0	0	0	0
Total Energy Supply from QF Contracts	1,718	1,718	1,716	1,716	1,714	1,713	1,718	1,721
Total Existing & Planned Renewable Contracts	1,009	1,004	978	971	908	879	873	875
Total Energy Supply from Other Bilateral Contracts	5,167	4,638	4,185	3,008	2,207	1,457	1,375	1,664
Total Contractual Resources	**9,485**	**8,948**	**6,879**	**5,696**	**4,829**	**4,050**	**3,966**	**4,259**
TOTAL EXISTING & PLANNED ENERGY RESOURCES	**16,635**	**15,227**	**13,286**	**12,175**	**11,162**	**10,742**	**10,361**	**10,894**
SUPPLY/DEMAND BALANCE	**2,157**	**3,908**	**6,190**	**7,647**	**9,005**	**9,771**	**10,489**	**10,291**
Aging Plant Replacement	**1,096**	**2,192**	**3,287**	**4,383**	**4,383**	**4,383**	**4,383**	**4,383**
TOTAL NEED, INCLUDING AGING PLANT REPLACEMENT	**3,253**	**6,099**	**9,477**	**12,030**	**13,388**	**14,154**	**14,872**	**14,674**
ADDITIONAL PREFERRED RESOURCES								
Uncommitted Energy Efficiency	141	419	687	929	1,148	1,431	1,741	2,066
Renewables	574	2,453	2,710	2,920	3,236	3,672	4,075	4,460
Distributed Generation/ CHP	to be developed in 2006 by Energy Commission and CPUC							
TOTAL ADDITIONAL PREFERRED RESOURCES (*)	**715**	**2,872**	**3,397**	**3,849**	**4,384**	**5,103**	**5,816**	**6,526**
ADDITIONAL NON-DESIGNATED NEED (*)	**2,538**	**3,227**	**6,080**	**8,181**	**9,004**	**9,051**	**9,056**	**8,148**

* - The total preferred resources will increase and the open source need will decrease when DG/CHP targets are established in 2006.

Table B-16
Annual Aggregated Capacity Resource Accounting Table
SDG&E Low Demand Case

	2009	2010	2011	2012	2013	2014	2015	2016
PEAK DEMAND (MW)								
Peak Service Area Demand (low case) (*)	4,488	4,553	4,617	4,682	4,746	4,809	4,872	4,933
Peak Bundled Customer Demand (low case)	3,890	3,951	4,011	4,073	4,134	4,194	4,254	4,312
Reserve Margin (at 15%)	673	683	692	702	712	721	731	740
Firm Sales Obligations	0	0	0	0	0	0	0	0
Firm Peak Requirement	**4,563**	**4,634**	**4,703**	**4,775**	**4,846**	**4,915**	**4,985**	**5,052**
EXISTING & PLANNED CAPACITY								
Utility-Controlled Physical Resources								
Nuclear	377	311	311	311	311	311	311	311
Fossil	588	588	588	588	588	588	588	588
Total Dependable Hydro Capacity	40	40	40	40	40	40	40	40
Total Utility-Controlled Physical Resources	**1,005**	**938**	**938**	**938**	**938**	**938**	**938**	**938**
Contractual Resources								
DWR Contracts	2,103	2,103	718	26	26	0	0	0
QF Contracts	221	221	221	221	221	221	221	221
Renewable Contracts (**)	120	120	116	116	107	105	104	105
Other Bilateral Contracts (**)	720	724	727	731	735	651	656	661
Total Contractual Resources	**3,164**	**3,167**	**1,782**	**1,094**	**1,089**	**977**	**981**	**986**
TOTAL EXISTING & PLANNED CAPACITY	**4,168**	**4,106**	**2,720**	**2,032**	**2,027**	**1,915**	**1,919**	**1,925**
Existing Interruptible/ Emergency Programs	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
SUPPLY/DEMAND BALANCE	**395**	**528**	**1,983**	**2,743**	**2,819**	**3,000**	**3,065**	**3,127**
Aging Plant Replacement	**405**	**810**	**1,214**	**1,619**	**1,619**	**1,619**	**1,619**	**1,619**
TOTAL NEED, INCLUDING AGING PLANT REPLACEMENT	**800**	**1,338**	**3,198**	**4,362**	**4,438**	**4,619**	**4,684**	**4,746**
ADDITIONAL PREFERRED RESOURCES								
Uncommitted Energy Efficiency	48	103	152	196	242	300	363	423
Uncommitted Dispatchable Demand Response	224	228	231	234	237	240	244	247
Renewables	66	428	546	567	601	647	689	728
Distributed Generation/ CHP	to be developed in 2006 by Energy Commission and CPUC							
TOTAL ADDITIONAL PREFERRED RESOURCES (***)	**338**	**759**	**929**	**997**	**1,080**	**1,187**	**1,296**	**1,398**
ADDITIONAL NON-DESIGNATED NEED (***)	**461**	**579**	**2,269**	**3,365**	**3,357**	**3,431**	**3,389**	**3,349**

* - Peak service area demand is used for calculation of the uncommitteed dispatchable demand reponse targets.

** - Planning area data are presented here because the IOU-specific data are confidential.

*** - Total preferred resource will increase and the open source need will decrease when DG/CHP targets are established in 2006.

Table B-17
Annual Aggregated Capacity Resource Accounting Table
SDG&E Base Demand Case

	2009	2010	2011	2012	2013	2014	2015	2016
PEAK DEMAND (MW)								
Peak Service Area Demand (base case) (*)	4,520	4,586	4,652	4,718	4,784	4,848	4,909	4,970
Peak Bundled Customer Demand (base case)	3,921	3,984	4,046	4,109	4,171	4,232	4,290	4,348
Reserve Margin (at 15%)	678	688	698	708	718	727	736	746
Firm Sales Obligations	0	0	0	0	0	0	0	0
Firm Peak Requirement	**4,599**	**4,672**	**4,744**	**4,817**	**4,889**	**4,959**	**5,026**	**5,094**
EXISTING & PLANNED CAPACITY								
Utility-Controlled Physical Resources								
Nuclear	377	311	311	311	311	311	311	311
Fossil	588	588	588	588	588	588	588	588
Total Dependable Hydro Capacity	40	40	40	40	40	40	40	40
Total Utility-Controlled Physical Resources	**1,005**	**938**	**938**	**938**	**938**	**938**	**938**	**938**
Contractual Resources								
DWR Contracts	2,103	2,103	718	26	26	0	0	0
QF Contracts	221	221	221	221	221	221	221	221
Renewable Contracts (**)	120	120	116	116	107	105	104	105
Other Bilateral Contracts (**)	720	724	727	731	735	651	656	661
Total Contractual Resources	**3,164**	**3,167**	**1,782**	**1,094**	**1,089**	**977**	**981**	**986**
TOTAL EXISTING & PLANNED CAPACITY	**4,168**	**4,106**	**2,720**	**2,032**	**2,027**	**1,915**	**1,919**	**1,925**
Existing Interruptible/ Emergency Programs	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
SUPPLY/DEMAND BALANCE	**431**	**566**	**2,024**	**2,785**	**2,861**	**3,044**	**3,107**	**3,169**
Aging Plant Replacement	**405**	**810**	**1,214**	**1,619**	**1,619**	**1,619**	**1,619**	**1,619**
TOTAL NEED, INCLUDING AGING PLANT REPLACEMENT	**835**	**1,376**	**3,238**	**4,404**	**4,480**	**4,663**	**4,726**	**4,788**
ADDITIONAL PREFERRED RESOURCES								
Uncommitted Energy Efficiency	48	103	152	196	242	300	363	423
Uncommitted Dispatchable Demand Response	226	229	233	236	239	242	245	249
Renewables	66	428	546	567	601	647	689	728
Distributed Generation/ CHP	to be developed in 2006 by Energy Commission and CPUC							
TOTAL ADDITIONAL PREFERRED RESOURCES (***)	**340**	**760**	**931**	**999**	**1,082**	**1,189**	**1,297**	**1,400**
ADDITIONAL NON-DESIGNATED NEED (***)	**495**	**615**	**2,307**	**3,405**	**3,398**	**3,473**	**3,429**	**3,388**

* - Peak service area demand is used for calculation of the uncommitteed dispatchable demand reponse targets.

** - Planning area data are presented here because the IOU-specific data are confidential.

*** - Total preferred resource will increase and the open source need will decrease when DG/CHP targets are established in 2006.

Table B-18
Annual Aggregated Capacity Resource Accounting Table
SDG&E High Demand Case

	2009	2010	2011	2012	2013	2014	2015	2016
PEAK DEMAND (MW)								
Peak Service Area Demand (high case) (*)	4,558	4,635	4,710	4,787	4,864	4,940	5,015	5,088
Peak Bundled Customer Demand (high case)	3,960	4,032	4,104	4,178	4,251	4,324	4,395	4,466
Reserve Margin (at 15%)	684	695	707	718	730	741	752	763
Firm Sales Obligations	0	0	0	0	0	0	0	0
Firm Peak Requirement	**4,644**	**4,727**	**4,811**	**4,896**	**4,981**	**5,065**	**5,147**	**5,229**
EXISTING & PLANNED CAPACITY								
Utility-Controlled Physical Resources								
Nuclear	377	311	311	311	311	311	311	311
Fossil	588	588	588	588	588	588	588	588
Total Dependable Hydro Capacity	40	40	40	40	40	40	40	40
Total Utility-Controlled Physical Resources	**1,005**	**938**	**938**	**938**	**938**	**938**	**938**	**938**
Contractual Resources								
DWR Contracts	2,103	2,103	718	26	26	0	0	0
QF Contracts	221	221	221	221	221	221	221	221
Renewable Contracts (**)	120	120	116	116	107	105	104	105
Other Bilateral Contracts (**)	720	724	727	731	735	651	656	661
Total Contractual Resources	**3,164**	**3,167**	**1,782**	**1,094**	**1,089**	**977**	**981**	**986**
TOTAL EXISTING & PLANNED CAPACITY	**4,168**	**4,106**	**2,720**	**2,032**	**2,027**	**1,915**	**1,919**	**1,925**
Existing Interruptible/ Emergency Programs	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
SUPPLY/DEMAND BALANCE	**475**	**621**	**2,090**	**2,864**	**2,953**	**3,150**	**3,228**	**3,305**
Aging Plant Replacement	**405**	**810**	**1,214**	**1,619**	**1,619**	**1,619**	**1,619**	**1,619**
TOTAL NEED, INCLUDING AGING PLANT REPLACEMENT	**880**	**1,431**	**3,305**	**4,483**	**4,572**	**4,769**	**4,847**	**4,924**
ADDITIONAL PREFERRED RESOURCES								
Uncommitted Energy Efficiency	48	103	152	196	242	300	363	423
Uncommitted Dispatchable Demand Response	228	232	236	239	243	247	251	254
Renewables	66	428	546	567	601	647	689	728
Distributed Generation/ CHP	to be developed in 2006 by Energy Commission and CPUC							
TOTAL ADDITIONAL PREFERRED RESOURCES (***)	**342**	**763**	**934**	**1,002**	**1,086**	**1,194**	**1,303**	**1,405**
ADDITIONAL NON-DESIGNATED NEED (***)	**538**	**668**	**2,371**	**3,481**	**3,486**	**3,575**	**3,544**	**3,518**

* - Peak service area demand is used for calculation of the uncommitteed dispatchable demand reponse targets.
** - Planning area data are presented here because the IOU-specific data are confidential.
*** - Total preferred resource will increase and the open source need will decrease when DG/CHP targets are established in 2006.

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Appendix D: Errata

p. 65, footnote 121 should read: “Mureau, June 30 TR at 65, 75; and SDG&E July 14 comment letter” rather than “… July 28 comment letter.”

p. 75, footnote 160 should read: “*Id.* at 99 and SDG&E July 14 comment letter” rather than “… July 22 comment.”

p. 90, footnote 174 should read: “PG&E April 1 filing, ‘Energy Commission Integrated Energy Policy Report PG&E Electric Resource Supply & Transmission Plan,’ page 13.”

p. 91, footnote 175 should read: “*Ibid.*”

p. 99, footnote 189 should read: “SCE April 1 filing, ‘Comments of Southern California Edison Company to the scenarios filed with the California Energy Commission for the 2005 Integrated Energy Policy Report,’ page 13.”

p. 99, footnote 192 should read: “Southern California Edison’s written comments to California Energy Commission’s *Investor-Owned Utility Resource Plan Summary Assessment* Report, July 22, 2005, p. 6.”

p. 99, footnote 194 should read: “Southern California Edison’s written comments to California Energy Commission’s *Investor-Owned Utility Resource Plan Summary Assessment* Report, July 22, 2005, p. 6.”

p. 123, footnotes 244, 246 and 247 should read: “Southern California Gas Company and San Diego Gas and Electric Company presentation…” rather than “Sempra Presentation…”